Relion® 650 series

Generator protection REG650 ANSI
Application Manual

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This product complies with the directive of the Council of the European Communities on the approximation of the laws of the Member States relating to electromagnetic compatibility (EMC Directive 2004/108/EC) and concerning electrical equipment for use within specified voltage limits (Low-voltage directive 2006/95/EC). This conformity is the result of tests conducted by ABB in accordance with the product standards EN 50263 and EN 60255-26 for the EMC directive, and with the product standards EN 60255-1 and EN 60255-27 for the low voltage directive. The product is designed in accordance with the international standards of the IEC 60255 series and ANSI C37.90. The DNP protocol implementation in the IED conforms to "DNP3 Intelligent Electronic Device (IED) Certification Procedure Subset Level 2", available at www.dnp.org .

Table of contents

Section 1 Introduction

1.1 This manual

The application manual contains application descriptions and setting guidelines sorted per function. The manual can be used to find out when and for what purpose a typical protection function can be used. The manual can also be used when calculating settings.

1.2 Intended audience

This manual addresses the protection and control engineer responsible for planning, pre-engineering and engineering.

The protection and control engineer must be experienced in electrical power engineering and have knowledge of related technology, such as protection schemes and communication principles.

1.3 Product documentation

1.3.1 Product documentation set

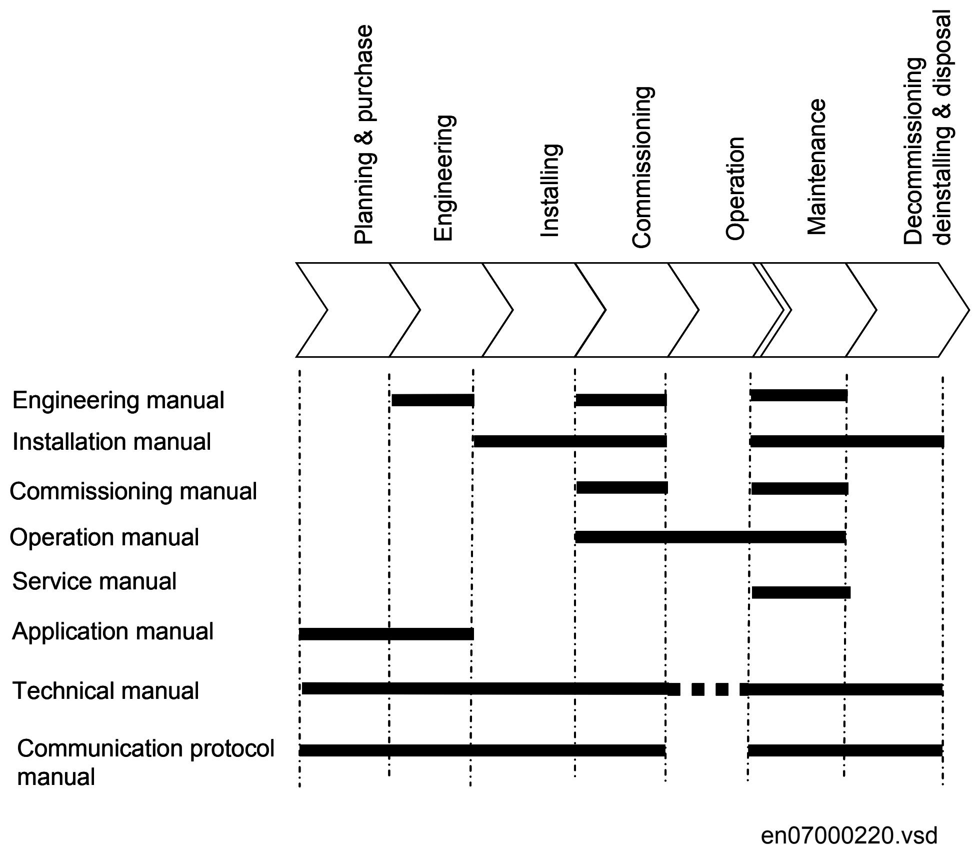


Figure 1: The intended use of manuals in different lifecycles

The engineering manual contains instructions on how to engineer the IEDs using the different tools in PCM600. The manual provides instructions on how to set up a PCM600 project and insert IEDs to the project structure. The manual also recommends a sequence for engineering of protection and control functions, LHMI functions as well as communication engineering for IEC 60870-5-103, IEC 61850 and DNP3.

The installation manual contains instructions on how to install the IED. The manual provides procedures for mechanical and electrical installation. The chapters are organized in chronological order in which the IED should be installed.

The commissioning manual contains instructions on how to commission the IED. The manual can also be used by system engineers and maintenance personnel for assistance

during the testing phase. The manual provides procedures for checking of external circuitry and energizing the IED, parameter setting and configuration as well as verifying settings by secondary injection. The manual describes the process of testing an IED in a substation which is not in service. The chapters are organized in chronological order in which the IED should be commissioned.

The operation manual contains instructions on how to operate the IED once it has been commissioned. The manual provides instructions for monitoring, controlling and setting the IED. The manual also describes how to identify disturbances and how to view calculated and measured power grid data to determine the cause of a fault.

The service manual contains instructions on how to service and maintain the IED. The manual also provides procedures for de-energizing, de-commissioning and disposal of the IED.

The application manual contains application descriptions and setting guidelines sorted per function. The manual can be used to find out when and for what purpose a typical protection function can be used. The manual can also be used when calculating settings.

The technical manual contains application and functionality descriptions and lists function blocks, logic diagrams, input and output signals, setting parameters and technical data sorted per function. The manual can be used as a technical reference during the engineering phase, installation and commissioning phase, and during normal service.

The communication protocol manual describes a communication protocol supported by the IED. The manual concentrates on vendor-specific implementations.

The point list manual describes the outlook and properties of the data points specific to the IED. The manual should be used in conjunction with the corresponding communication protocol manual.

1.3.2 Document revision history

Document revision/date	History
-/March 2012	First release
A/June 2012	Minor corrections made

1.3.3 Related documents

Documents related to REG650	Identity number
Application manual	1MRK 502 042-UUS
Technical manual	1MRK 502 043-UUS
Commissioning manual	1MRK 502 044-UUS
Product Guide	1MRK 502 045-BUS
Type test certificate	1MRK 502 045-TUS
Rotor Ground Fault Protection with Injection Unit RXTTE4 and REG670	1MRG001910
Application notes for Circuit Breaker Control	1MRG006806

650 series manuals	Identity number
Communication protocol manual, DNP3	1MRK 511 257-UUS
Communication protocol manual, IEC 61850–8–1	1MRK 511 258-UUS
Communication protocol manual, IEC 60870-5-103	1MRK 511 259-UUS
Cyber Security deployment guidelines	1MRK 511 268-UUS
Point list manual, DNP3	1MRK 511 260-UUS
Engineering manual	1MRK 511 261-UUS
Operation manual	1MRK 500 095-UUS
Installation manual	1MRK 514 015-UUS

1.4 Symbols and conventions

1.4.1 Symbols

The electrical warning icon indicates the presence of a hazard which could result in electrical shock.

The warning icon indicates the presence of a hazard which could result in personal injury.

The caution icon indicates important information or warning related to the concept discussed in the text. It might indicate the presence of a hazard which could result in corruption of software or damage to equipment or property.

The information icon alerts the reader of important facts and conditions.

The tip icon indicates advice on, for example, how to design your project or how to use a certain function.

Although warning hazards are related to personal injury, it is necessary to understand that under certain operational conditions, operation of damaged equipment may result in degraded process performance leading to personal injury or death. Therefore, comply fully with all warning and caution notices.

1.4.2 Document conventions

A particular convention may not be used in this manual.

- Abbreviations and acronyms in this manual are spelled out in the glossary. The glossary also contains definitions of important terms.
- Push button navigation in the LHMI menu structure is presented by using the push button icons.
  To navigate between the options, use and .
- HMI menu paths are presented in bold.
  Select **Main menu/Settings**.
- LHMI messages are shown in Courier font.
  To save the changes in non-volatile memory, select `Yes` and press .
- Parameter names are shown in italics.
  The function can be enabled and disabled with the *Operation* setting.
- The ^ character in front of an input or output signal name in the function block symbol given for a function, indicates that the user can set an own signal name in PCM600.
- The * character after an input or output signal name in the function block symbol given for a function, indicates that the signal must be connected to another function block in the application configuration to achieve a valid application configuration.
- Dimensions are provided both in inches and mm. If it is not specifically mentioned then the dimension is in mm.

Section 2 Application

2.1 REG650 application

REG650 is used for the protection and monitoring of generating plants. The IED is especially suitable for applications in distributed control systems with high demands on reliability. It is intended mainly for small and medium size generation stations.

REG670 may be used when more extensive protection systems are required or in combination with REG650 to provide redundant schemes.

A wide range of protection functions is available to achieve full and reliable protection for different types of generating plants, for example hydro power plants and thermal power plants. This enables adaptation to the protection requirements of most generating plants.

Protection functions are available for detecting and clearing internal faults, such as generator stator short circuits and ground faults, generator rotor ground faults, unit transformer short circuits and ground faults and faults in the external power system, fed from the generating plant.

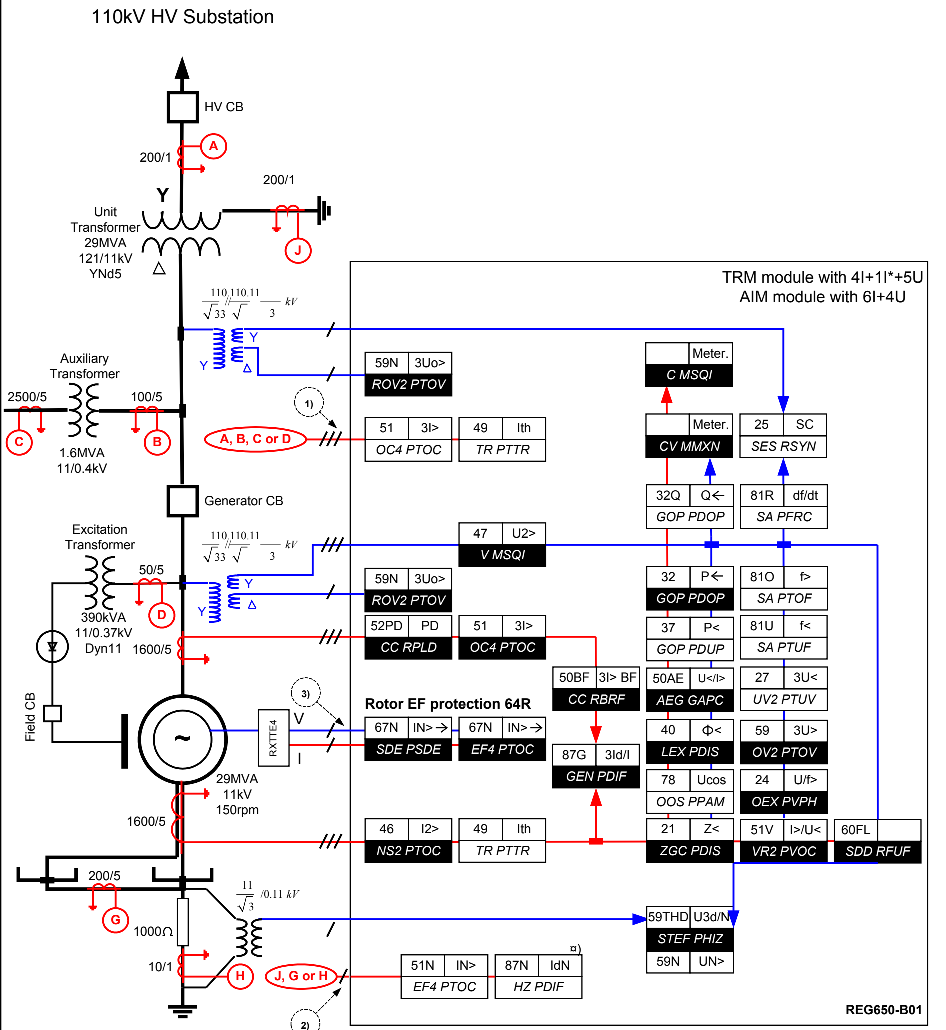
Two packages have been defined for the following applications:

- Generator protection IED including generator differential protection (B01A)
- Generator-transformer unit protection IED including transformer differential protection (B05A)

In many generating plants, the protection system can be designed with a combination of the two packages, that is, two IEDs of either same type or different types, will give redundant protection for a generating unit (generator and unit transformer) depending on the requirements for the plant design.

The packages are configured and ready for use. Analogue inputs and binary input/output circuits are pre-defined.

The pre-configured IED can be changed and adapted with the graphical configuration tool.



¤) Requires dedicated CT cores, external resistor and metrosil for correct operation

Note:

1) Input for independent non-directional OC and overload functions. It can be used for different purposes (e.g. OC protection for either Auxiliary trafo or Excitation trafo or Step-up transformer HV side)

2) Input for independent non-directional EF function. It can be used for different purposes (e.g. as stator EF protection or turn-to-turn protection for generators with split winding or even HV side EF protection). Alternatively it can be used for High-Impedance REF protection.

3) Input for independent directional (sensitive) EF function. It can be used for different purposes (e.g. as rotor EF with RXTTE4 or stator EF for generators operating in parallel)

4) An example to indicate the functions, marked in black are enabled in settings.

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Figure 2: Generator protection IED including generator differential protection (B01A)

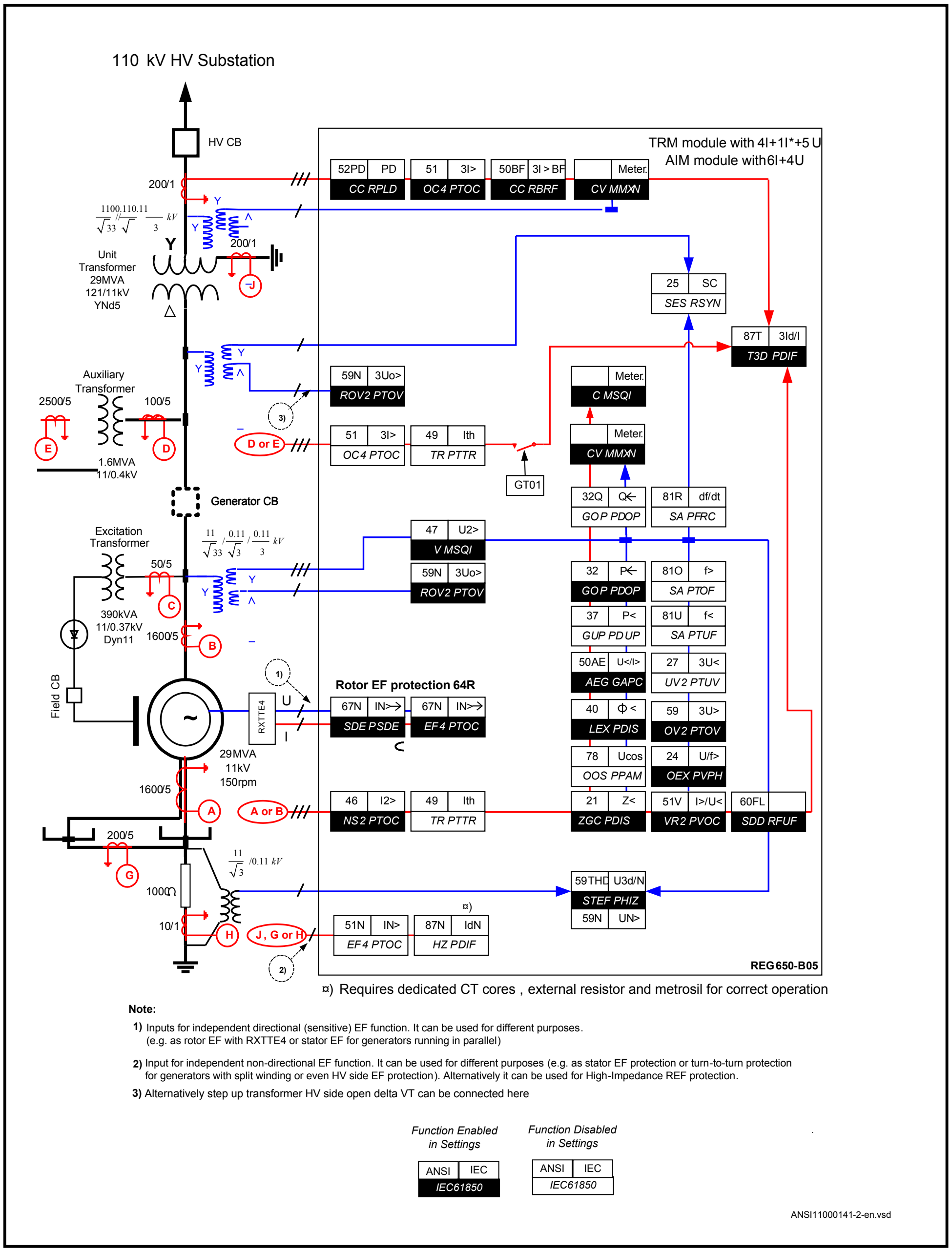

Figure 3: Generator-transformer unit protection IED including transformer differential protection (B05A)

2.2 Available functions

2.2.1 Main protection functions

IEC 61850/ Function block name	ANSI	Function description	Generator		
			REG650	REG650 (B01A) Gen diff	REG650 (B05A) Gen+Trafo diff
Differential protection					
T3WPDIF	87T	Transformer differential protection, three winding	0–1		1
HZPDIF	87	1Ph High impedance differential protection	1	1	1
GENPDIF	87G	Generator differential protection	0–1	1	
Impedance protection					
ZGCPDIS	21G	Underimpedance protection for generators and transformers	0–1	1	1
LEXPDIS	40	Loss of excitation	0–1	1	1
OOSPPAM	78	Out-of-step protection	0–1	1	1
LEPDIS		Load encroachment	0–1	1	1

2.2.2 Back-up protection functions

IEC 61850/ Function block name	ANSI	Function description	Generator		
			REG650	REG650 (B01A) Gen diff	REG650 (B05A) Gen+Trafo diff
Current protection					
OC4PTOC	51	Four step phase overcurrent protection, 3–phase output	0–2	2	2
EF4PTOC	51N/67N	Four step residual overcurrent protection, zero/negative sequence direction	0–2	2	2
SDEPSDE	67N	Sensitive directional residual overcurrent and power protection	0–1	1	1
TRPTTR	49	Thermal overload protection, two time constants	0–2	2	2
CCRBRF	50BF	Breaker failure protection, 3–phase activation and output	0–1	1	1
CCRPLD	52PD	Pole discordance protection	0–1	1	1
GUPPDUP	37	Directional underpower protection	0–1	1	1

Table continues on next page

IEC 61850/ Function block name	ANSI	Function description	Generator		
			REG650	REG650 (B01A) Gen diff	REG650 (B05A) Gen+Trafo diff
GOPPDOP	32	Directional overpower protection	0–2	2	2
AEGGAPC	50AE	Accidental energizing protection for synchronous generator	0–1	1	1
NS2PTOC	46I2	Negative-sequence time overcurrent protection for machines	0–1	1	1
VR2PVOC	51V	Voltage-restrained time overcurrent protection	0–1	1	1
Voltage protection					
UV2PTUV	27	Two step undervoltage protection	0–1	1	1
OV2PTOV	59	Two step overvoltage protection	0–1	1	1
ROV2PTOV	59N	Two step residual overvoltage protection	0–2	2	2
OEXPVPH	24	Overexcitation protection	0–1	1	1
STEFPHIZ	59THD	100% Stator earth fault protection, 3rd harmonic based	0–1	1	1
-	64R	Rotor ground protection with RXTTE4 injection unit	0–1	0–1	0–1
Frequency protection					
SAPTUF	81	Underfrequency function	0–4	4	4
SAPTOF	81	Overfrequency function	0–4	4	4
SAPFRC	81	Rate-of-change frequency protection	0–2	2	2

2.2.3 Control and monitoring functions

IEC 61850/Function block name	ANSI	Function description	Generator		
			REG650	REG650 (B01A) Gen diff	REG650 (B05A) Gen+Trafo diff
Control					
SESRSYN	25	Synchrocheck, energizing check, and synchronizing	0–1	1	1
QCBAY		Bay control	1	1	1
LOCREM		Handling of LR-switch positions	1	1	1
LOCREMCTRL		LHMI control of Permitted Source To Operate (PSTO)	1	1	1
CBC1		Circuit breaker for 1CB	0–1	1	
CBC2		Circuit breaker for 2CB	0–1		1

Table continues on next page

IEC 61850/Function block name	ANSI	Function description	Generator		
			REG650	REG650 (B01A) Gen diff	REG650 (B05A) Gen+Trafo diff
SLGGIO		Logic Rotating Switch for function selection and LHMI presentation	15	15	15
VSGGIO		Selector mini switch extension	20	20	20
DPGGIO		IEC 61850 generic communication I/O functions double point	16	16	16
SPC8GGIO		Single point generic control 8 signals	5	5	5
AUTOBITS		AutomationBits, command function for DNP3.0	3	3	3
I103CMD		Function commands for IEC60870-5-103	1	1	1
I103IEDCMD		IED commands for IEC60870-5-103	1	1	1
I103USRCMD		Function commands user defined for IEC60870-5-103	4	4	4
I103GENCMD		Function commands generic for IEC60870-5-103	50	50	50
I103POSCMD		IED commands with position and select for IEC60870-5-103	50	50	50
Secondary system supervision					
SDDRFUF		Fuse failure supervision	0–1	1	1
TCSSCBR		Breaker close/trip circuit monitoring	3	3	3
Logic					
SMPPTRC	94	Tripping logic, common 3–phase output	1–6	6	6
TMAGGIO		Trip matrix logic	12	12	12
OR		Configurable logic blocks, OR gate	283	283	283
INVERTER		Configurable logic blocks, Inverter gate	140	140	140
PULSETIMER		Configurable logic blocks, Pulse timer	40	40	40
GATE		Configurable logic blocks, Controllable gate	40	40	40
XOR		Configurable logic blocks, exclusive OR gate	40	40	40
LOOPDELAY		Configurable logic blocks, loop delay	40	40	40
TIMERSET		Configurable logic blocks, timer function block	40	40	40
AND		Configurable logic blocks, AND gate	280	280	280
SRMEMORY		Configurable logic blocks, set-reset memory flip-flop gate	40	40	40
RSMEMORY		Configurable logic blocks, reset-set memory flip-flop gate	40	40	40
FXDSIGN		Fixed signal function block	1	1	1
B16I		Boolean 16 to Integer conversion	16	16	16
B16IFCVI		Boolean 16 to Integer conversion with logic node representation	16	16	16
IB16A		Integer to Boolean 16 conversion	16	16	16

Table continues on next page

IEC 61850/Function block name	ANSI	Function description	Generator		
			REG650	REG650 (B01A) Gen diff	REG650 (B05A) Gen+Trafo diff
IB16FCVB		Integer to Boolean 16 conversion with logic node representation	16	16	16
Monitoring					
CVMMXN		Measurements	6	6	6
CMMXU		Phase current measurement	10	10	10
VMMXU		Phase-phase voltage measurement	6	6	6
CMSQI		Current sequence component measurement	6	6	6
VMSQI		Voltage sequence measurement	6	6	6
VNMMXU		Phase-neutral voltage measurement	6	6	6
AISVBAS		Function block for service values presentation of the analog inputs	1	1	1
TM_P_P2		Function block for service values presentation of primary analog inputs 600TRM	1	1	1
AM_P_P4		Function block for service values presentation of primary analog inputs 600AIM	1	1	1
TM_S_P2		Function block for service values presentation of secondary analog inputs 600TRM	1	1	1
AM_S_P4		Function block for service values presentation of secondary analog inputs 600AIM	1	1	1
CNTGGIO		Event counter	5	5	5
DRPRDRE		Disturbance report	1	1	1
AxRADR		Analog input signals	4	4	4
BxRBDR		Binary input signals	6	6	6
SPGGIO		IEC 61850 generic communication I/O functions	64	64	64
SP16GGIO		IEC 61850 generic communication I/O functions 16 inputs	16	16	16
MVGGIO		IEC 61850 generic communication I/O functions	16	16	16
MVEXP		Measured value expander block	66	66	66
SPVNZBAT		Station battery supervision	0–1	1	1
SSIMG	63	Insulation gas monitoring function	0–2	2	2
SSIML	71	Insulation liquid monitoring function	0–2	2	2
SSCBR		Circuit breaker condition monitoring	0–1	1	1
I103MEAS		Measurands for IEC60870-5-103	1	1	1
I103MEASUSR		Measurands user defined signals for IEC60870-5-103	3	3	3
I103AR		Function status auto-recloser for IEC60870-5-103	1	1	1

Table continues on next page

IEC 61850/Function block name	ANSI	Function description	Generator		
			REG650	REG650 (B01A) Gen diff	REG650 (B05A) Gen+Trafo diff
I103EF		Function status ground-fault for IEC60870-5-103	1	1	1
I103FLTPROT		Function status fault protection for IEC60870-5-103	1	1	1
I103IED		IED status for IEC60870-5-103	1	1	1
I103SUPERV		Supervison status for IEC60870-5-103	1	1	1
I103USRDEF		Status for user defined signals for IEC60870-5-103	20	20	20
Metering					
PCGGIO		Pulse counter logic	16	16	16
ETPMMTR		Function for energy calculation and demand handling	3	3	3

2.2.4 Communication

IEC 61850/Function block name	ANSI	Function description	Generator		
			REG650	REG650 (B01A) Gen diff	REG650 (B05A) Gen+Trafo diff
Station communication					
IEC61850-8-1		IEC 61850 communication protocol	1	1	1
DNPGEN		DNP3.0 for TCP/IP communication protocol	1	1	1
RS485DNP		DNP3.0 for EIA-485 communication protocol	1	1	1
CH1TCP		DNP3.0 for TCP/IP communication protocol	1	1	1
CH2TCP		DNP3.0 for TCP/IP communication protocol	1	1	1
CH3TCP		DNP3.0 for TCP/IP communication protocol	1	1	1
CH4TCP		DNP3.0 for TCP/IP communication protocol	1	1	1
OPTICALDNP		DNP3.0 for optical serial communication	1	1	1
MSTSERIAL		DNP3.0 for serial communication protocol	1	1	1
MST1TCP		DNP3.0 for TCP/IP communication protocol	1	1	1
MST2TCP		DNP3.0 for TCP/IP communication protocol	1	1	1
MST3TCP		DNP3.0 for TCP/IP communication protocol	1	1	1
MST4TCP		DNP3.0 for TCP/IP communication protocol	1	1	1
RS485GEN		RS485	1	1	1

Table continues on next page

IEC 61850/Function block name	ANSI	Function description	Generator		
			REG650	REG650 (B01A) Gen diff	REG650 (B05A) Gen+Trafo diff
OPTICALPROT		Operation selection for optical serial	1	1	1
RS485PROT		Operation selection for RS485	1	1	1
DNPFREC		DNP3.0 fault records for TCP/IP communication protocol	1	1	1
OPTICAL103		IEC60870-5-103 Optical serial communication	1	1	1
RS485103		IEC60870-5-103 serial communication for RS485	1	1	1
GOOSEINTLKRCV		Horizontal communication via GOOSE for interlocking	59	59	59
GOOSEBINRCV		GOOSE binary receive	4	4	4
ETHFRNT ETHLAN1 GATEWAY		Ethernet configuration of front port, LAN1 port and gateway	1	1	1
GOOSEDPRCV		GOOSE function block to receive a double point value	32	32	32
GOOSEINTRCV		GOOSE function block to receive an integer value	32	32	32
GOOSEMVRCV		GOOSE function block to receive a measurand value	16	16	16
GOOSESPRCV		GOOSE function block to receive a single point value	64	64	64

2.2.5 Basic IED functions

IEC 61850/Function block name	Function description	
Basic functions included in all products		
INTERRSIG	Self supervision with internal event list	1
SELFSUPEVLST	Self supervision with internal event list	1
TIMESYNCHGEN	Time synchronization	1
SNTP	Time synchronization	1
DTSBEGIN, DTSEND, TIMEZONE	Time synchronization, daylight saving	1
IRIG-B	Time synchronization	1
SETGRPS	Setting group handling	1
ACTVGRP	Parameter setting groups	1
TESTMODE	Test mode functionality	1
CHNGLCK	Change lock function	1
TERMINALID	IED identifiers	1
PRODINF	Product information	1

Table continues on next page

IEC 61850/Function block name	Function description	
SYSTEMTIME	System time	1
RUNTIME	IED Runtime comp	1
PRIMVAL	Primary system values	1
SMAI_20_1 - SMAI_20_12	Signal matrix for analog inputs	2
3PHSUM	Summation block 3 phase	12
GBASVAL	Global base values for settings	6
ATHSTAT	Authority status	1
ATHCHCK	Authority check	1
SPACOMMMAP	SPA communication mapping	1
FTPACCS	FTP access with password	1
DOSFRNT	Denial of service, frame rate control for front port	1
DOSLAN1	Denial of service, frame rate control for LAN1	1
DOSSCKT	Denial of service, socket flow control	1
SAFEFILECOPY	Safe file copy function	1
SPATD	Date and time via SPA protocol	1
BCSCONF	Basic communication system	1

2.3 REG650 application examples

2.3.1 Adaptation to different applications

The IED has a pre-defined configuration and it can be used in a wide range of applications. This is achieved by selecting a functionality from the comprehensive function library in the IED. A selection of applications is described below.

The following application examples show single IED applications where redundancy is not considered:

- Application 1: Single generator connected via an unit transformer to a High Voltage (HV) system
- Application 2: Single generator, including the auxiliary transformer, connected via a unit transformer to a High Voltage (HV) system
- Application 3: Generating unit, including both generator and unit transformer, connected to a solidly grounded High Voltage (HV) system
- Application 4: Generating unit, including both generator and unit transformer, connected to a high impedance grounded High Voltage (HV) system

The following application examples show double IED applications giving full protection function redundancy:

- Application 5: Single generator/transformer unit, connected to a solidly grounded High Voltage (HV) system, with redundant protection
- Application 6: Single generator/transformer unit, connected to a high impedance grounded High Voltage (HV) system, with redundant protection
- Application 7: Two generators having one three-winding unit transformer, connected to a solidly grounded High Voltage (HV) system, with redundant protection with unit differential protection including the generators
- Application 8: Two generators having one three-winding unit transformer, connected to a solidly grounded High Voltage (HV) system, with redundant protection with unit transformer differential protection

In the application examples two variants of REG650 are used:

- REG650 (B01A): Generator protection IED including generator differential protection (B01A)
- REG650 (B05A): Generator-transformer unit protection IED including transformer differential protection (B05A)

Other variants are also possible but the applications discussed here can be adapted to changed conditions.

The configuration enables the use for different applications by enable/disable protection functions to achieve a suitable functionality.

2.3.1.1 Single generator connected via a unit transformer to a High Voltage (HV) system

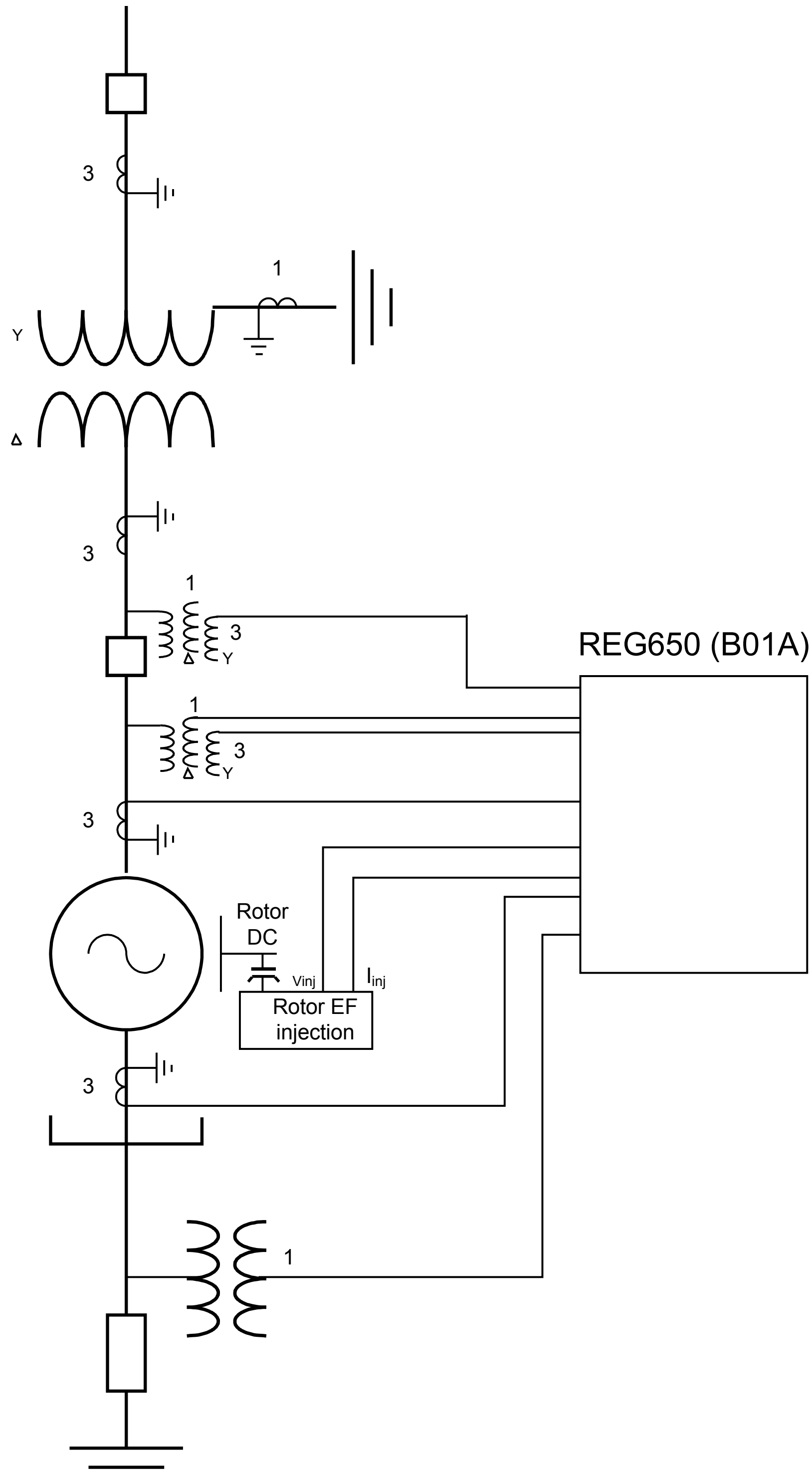

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Figure 4: Single generator connected via a unit transformer to a High Voltage (HV) system

REG650 (B01A) is used as the main protection for the generator. Redundancy can be achieved by using other protections.

Table 1: Data for the generator application example

Parameter	Value
Generator rated voltage ($V_{N,Gen}$)	1 – 20 kV
Generator rated power (S_N)	1 – 150 MVA
Short circuit power level infeed at HV-side	500 – 10000 MVA

2.3.1.2 Single generator, including the auxiliary transformer, connected via an unit transformer to a High Voltage (HV) system

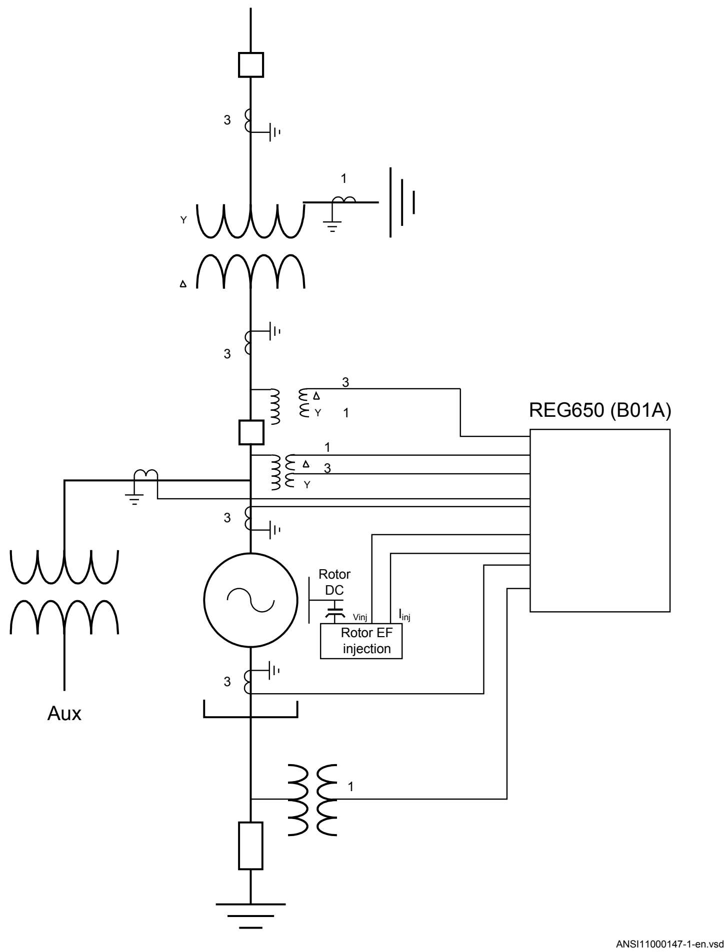


Figure 5: Single generator, including the auxiliary transformer, connected via an unit transformer to a High Voltage (HV) system

REG650 (B01A) is used as protection for the generator and for the transformer feeding the auxiliary system. Redundancy can be achieved by using other protections.

Table 2: Data for the generator application example

Parameter	Value
Generator rated voltage ($V_{N,Gen}$)	1– 20 kV
Generator rated power (S_N)	1– 150 MVA
Short circuit power level infeed at HV-side	500 – 10000 MVA

2.3.1.3 Generating unit, including both generator and unit transformer, connected to a solidly grounded High Voltage (HV) system

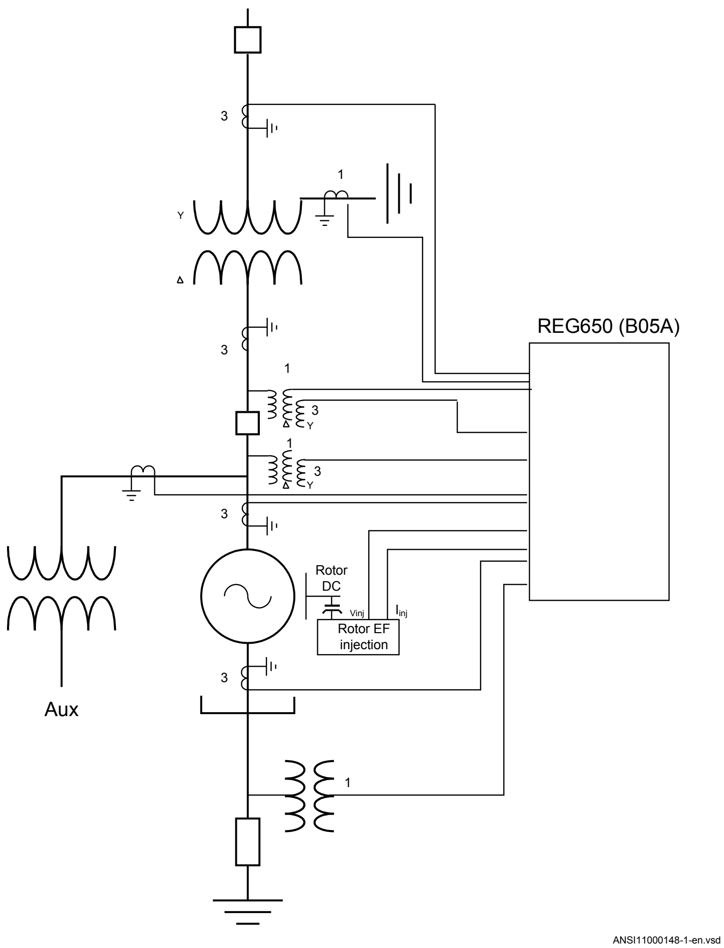


Figure 6: Generating unit, including both generator and unit transformer, connected to a solidly grounded High Voltage (HV) system

REG650 (B05A) is used as protection for the generator and for the unit transformer. Redundancy can be achieved by using other protections.

Table 3: Data for the generator application example

Parameter	Value
Generator rated voltage ($V_{N,Gen}$)	1 – 20 kV
Transformer high voltage side rated voltage ($V_{N,THV}$)	11 – 220 kV
Generator rated power (S_N)	1- 150 MVA
Short circuit power level infeed at HV-side	500 – 5000 MVA

2.3.1.4 Generating unit, including both generator and unit transformer, connected to a high impedance grounded High Voltage (HV) system

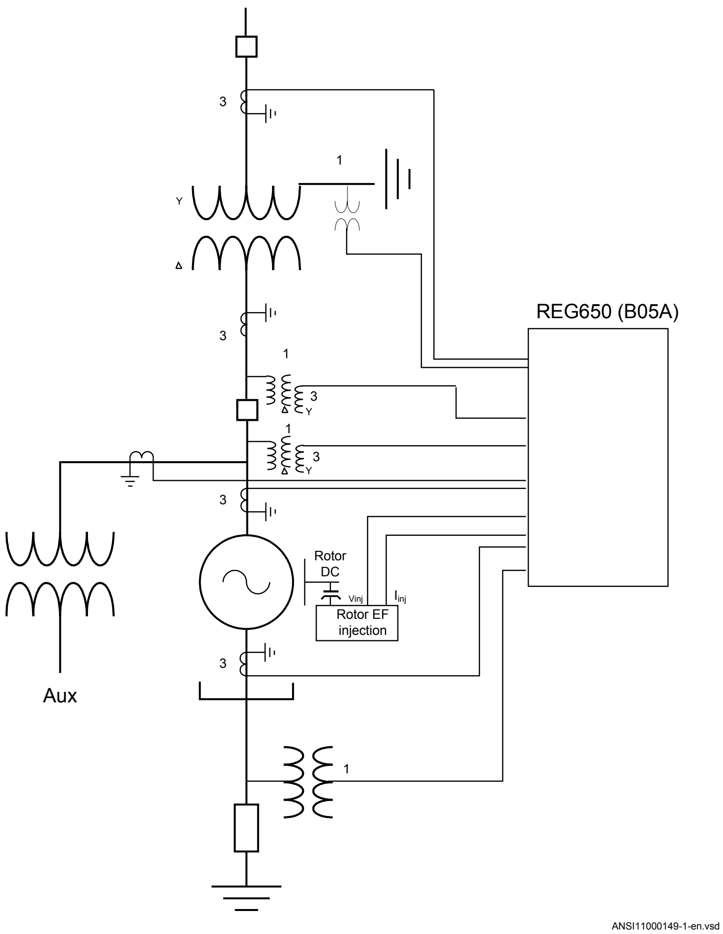


Figure 7: Generating unit, including both generator and unit transformer, connected to a high impedance grounded High Voltage (HV) system

REG650 (B05A) is used as protection for the generator and for the unit transformer. Redundancy can be achieved by using other protections.

Table 4: Data for the generator application example

Parameter	Value
Generator rated voltage ($V_{N,Gen}$)	1– 20 kV
Transformer high voltage side rated voltage ($V_{N,THV}$)	11– 220 kV
Generator rated power (S_N)	1- 150 MVA
Short circuit power level infeed at HV-side	500 – 5000 MVA

2.3.1.5 Functionality table

The proposal for functionality choice for the different application cases are shown in table 5.

The recommendations have the following meaning:

- Enabled: It is recommended to have the function activated in the application.
- Disabled: It is recommended to have the function deactivated in the application.
- Application dependent: The decision to have the function activated or not is dependent on the specific conditions in each case.

Applications 1 — 4 in table 5 are according to application examples given in previous sections.

Table 5: Recommended functions in the different application examples

Function	Application 1	Application 2	Application 3	Application 4
Generator differential protection GENPDIF (87G), (B01A)	Enabled	Enabled	—	—
Transformer differential protection T3WPDIF(87T), (B05A)	—	—	Enabled	Enabled
1Ph High impedance differential protection HZPDIF (87), (Stator ground fault protection)	Application dependent	Application dependent	Application dependent	Application dependent
Underimpedance protection for generators and transformers ZGCPDIS (21G)	Enabled	Enabled	Enabled	Enabled
Load encroachment LEPDIS	Application dependent	Application dependent	Application dependent	Application dependent
Out-of-step protection OOSPPAM (78)	Enabled	Enabled	Enabled	Enabled
Loss of excitation (underexcitation) protection LEXPDIS (40)	Enabled	Enabled	Enabled	Enabled
Four step phase overcurrent protection OC4PTOC (51_67), instance 1	Enabled Gen Term	Enabled Gen Term	Enabled HV side	Enabled HV side
Table continues on next page				

Function	Application 1	Application 2	Application 3	Application 4
Four step phase overcurrent protection OC4PTOC (51_67), instance 2	Enabled Aux T	Enabled Aux T	Enabled Aux T	Enabled Aux T
Four step residual overcurrent protection EF4PTOC (51N_67N), instance 1	Alt Rotor EF	Alt Rotor EF	Enabled T HV	Disabled
Four step residual overcurrent protection EF4PTOC (51N_67N), instance 2	Disabled	Disabled	Disabled	Disabled
Sensitive directional residual overcurrent and power protection SDEPSDE (67N)	Enabled Rotor EF	Enabled Rotor EF	Enabled Rotor EF	Enabled Rotor EF
Thermal overload protection TRPTTR (49), instance 1	Enabled	Enabled	Enabled	Enabled
Thermal overload protection TRPTTR (49), instance 2	Enabled Aux T	Enabled Aux T	Disabled	Disabled
Breaker failure protection CCRBRF (50BF)	Enabled	Enabled	Enabled	Enabled
Pole discordance protection CCRPLD (52PD)	Enabled	Enabled	Application dependent	Application dependent
Directional underpower protection GUPPDUP (37) (low forward power protection)	1)	1)	1)	1)
Directional overpower protection GOPPDOP (32), instance 1 (reverse power protection)	1)	1)	1)	1)
Directional overpower protection GOPPDOP (32), instance 2 (forward reactive power protection)	Application dependent	Application dependent	Disabled	Disabled
Accidental energizing protection for synchronous generator AEGGAPC (50AE),	Enabled	Enabled	Enabled	Enabled
Negative-sequence time overcurrent protection for machines NS2PTOC (46I2)	Enabled	Enabled	Enabled	Enabled
Voltage-restrained time overcurrent protection VR2PVOC (51V)	2)	2)	2)	2)
Two step undervoltage protection UV2PTUV (27), U<	Enabled	Enabled	Enabled	Enabled
Two step overvoltage protection OV2PTOV (59), U>	Enabled	Enabled	Enabled	Enabled
Two step residual overvoltage Protection ROV2PTOV (59N), U0>, instance 1	Enabled Gen Term	Enabled Gen Term	Enabled Gen Neutr point	Enabled Gen Neutr point
Two step residual overvoltage Protection ROV2PTOV (59N), U0>, instance 2	Enabled T sec side	Enabled T sec side	Enabled T sec side	Enabled T HV neutr point
Overexcitation protection OEXPVPH (24)	Enabled	Enabled	Enabled	Enabled
100% Stator ground fault protection, 3rd harmonic based STEFPHIZ (59THD)/ 95 % fundamental based	Enabled	Enabled	Application dependent	Application dependent
Underfrequency protection SAPTUF (81), instance 1	Enabled	Enabled	Enabled	Enabled
Underfrequency protection SAPTUF(81), instance 2	Disabled	Disabled	Disabled	Disabled
Underfrequency protection SAPTUF(81), instance 3	Disabled	Disabled	Disabled	Disabled
Underfrequency protection SAPTUF(81), instance 4	Disabled	Disabled	Disabled	Disabled
Overfrequency protection SAPTOF(81), instance 1	Enabled	Enabled	Enabled	Enabled
Overfrequency protection SAPTOF(81), instance 2	Disabled	Disabled	Disabled	Disabled
Overfrequency protection SAPTOF(81), instance 3	Disabled	Disabled	Disabled	Disabled
Table continues on next page				

Function	Application 1	Application 2	Application 3	Application 4
Overfrequency protection SAPTOF(81), instance 4	Disabled	Disabled	Disabled	Disabled
Rate-of-change frequency protection SAPFRC(81), instance 1	Application dependent	Application dependent	Application dependent	Application dependent
Rate-of-change frequency protection SAPFRC (81), instance 2	Disabled	Disabled	Disabled	Disabled
Synchrocheck, energizing check, and synchronizing SESRSYN (25)	Application dependent	Application dependent	Application dependent	Application dependent

1) The generator should have reverse power protection. If the generator consumes low reverse power at motor operation (< 1 % of S_N), low forward power protection should be used. In other cases, reverse power protection should be used.
2) Voltage-restrained time overcurrent protection add (VR2PVOC, 51V) can be used instead of the underimpedance protection.

2.3.1.6 Single generator/transformer unit, connected to a solidly grounded High Voltage (HV) system, with redundant protection

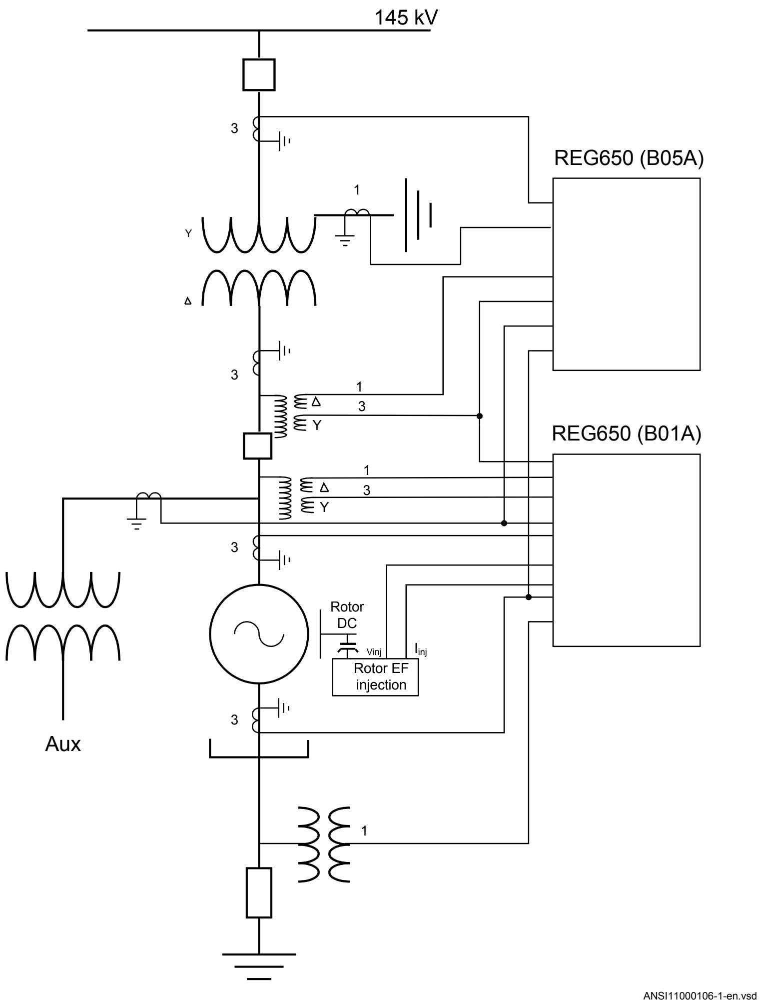


Figure 8: Single generator/transformer unit, connected to a solidly grounded High Voltage (HV) system, with redundant protection

REG650 (B01A) is used as the main protection for the generator and REG650 (B05A) is used as the main protection for the unit transformer and as back-up protection for the generator. The combination of the protections also gives redundant protection for the auxiliary system transformer.

Table 6: Data for the generator application example

Parameter	Value
Generator rated voltage ($V_{N,Gen}$)	1– 20 kV
Transformer high voltage side rated voltage ($V_{N,THV}$)	11 – 220 kV
Generator rated power (S_N)	1– 150 MVA
Short circuit power level infeed at HV-side	500 – 10000 MVA

2.3.1.7 Single generator/transformer unit, connected to a high impedance grounded High Voltage (HV) system, with redundant protection

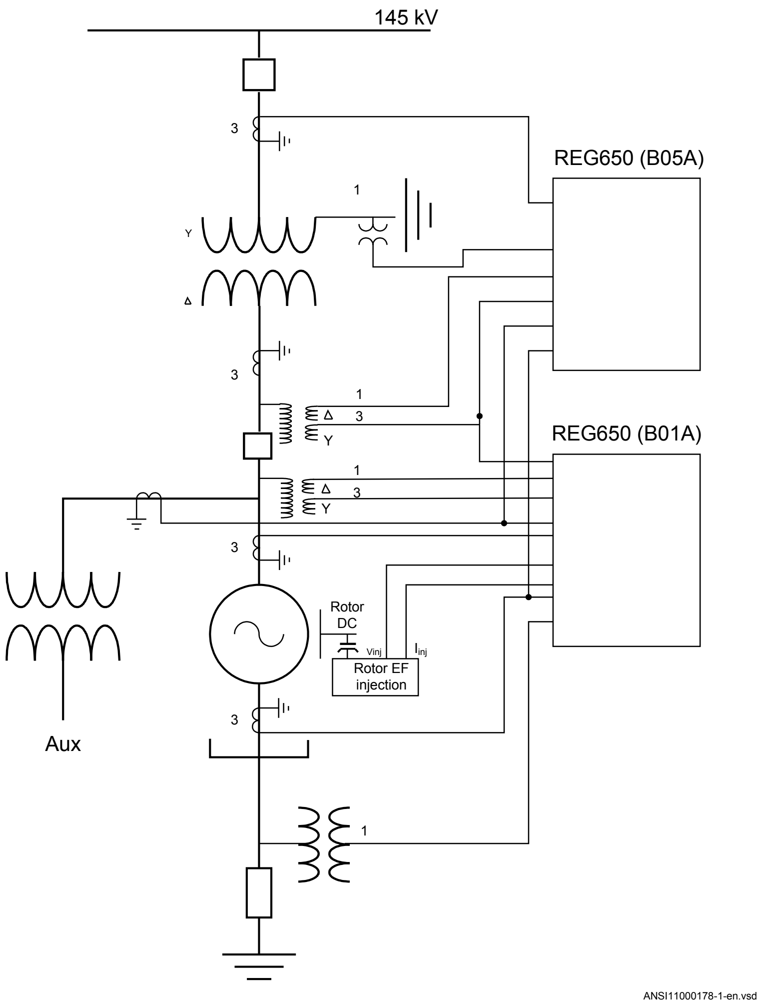


Figure 9: Single generator/transformer unit, connected to a high impedance grounded High Voltage (HV) system, with redundant protection

REG650 (B01A) is used as the main protection for the generator and REG650 (B05A) is used as the main protection for the unit transformer and as back-up protection for the generator. The combination of the protections also gives redundant protection for the auxiliary system transformer.

Table 7: Data for the generator application example

Parameter	Value
Generator rated voltage ($V_{N,Gen}$)	1– 20 kV
Transformer high voltage side rated voltage ($V_{N,THV}$)	11 – 220 kV
Generator rated power (S_N)	1– 150 MV
Short circuit power level infeed at HV-side	500 – 5000 MVA

2.3.1.8 Two generators having one three-winding unit transformer, connected to a solidly grounded High Voltage (HV) system, with redundant protection with unit differential protection including the generators

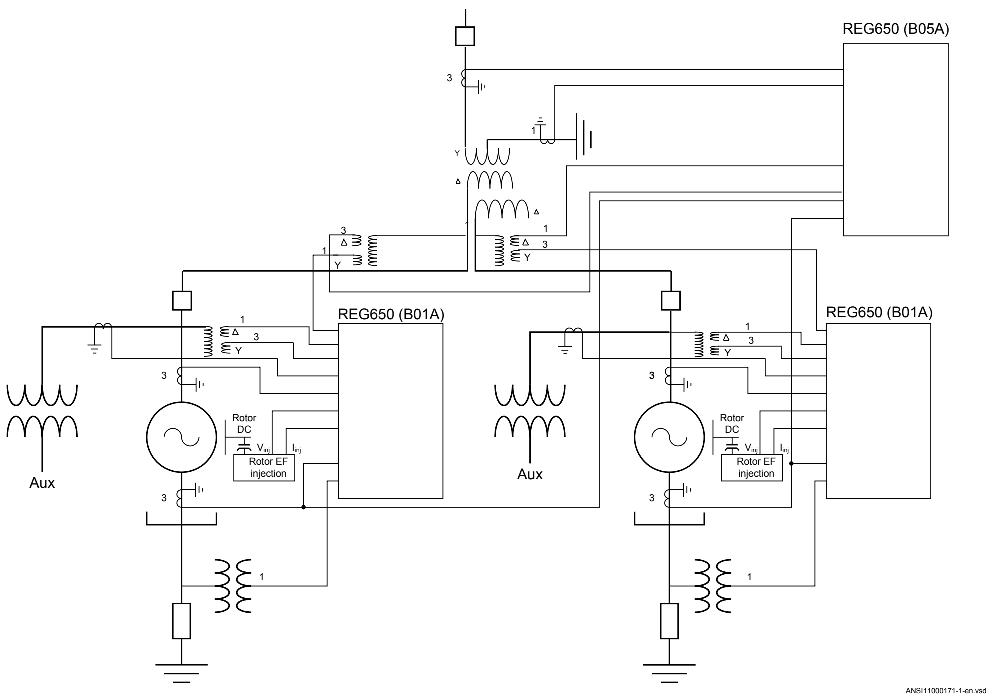


Figure 10: Two generators having one three-winding unit transformer, connected to a solidly grounded High Voltage (HV) system, with redundant protection with unit differential protection including the generators

REG650 (B01A) is used as the main protection for the generator and REG650 (B05A) is used as the main protection for the unit transformer and as back-up protection for the generator. The combination of the protections also gives redundant protection for the auxiliary system transformer.

Table 8: Data for the generator application example

Parameter	Value
Generator rated voltage ($V_{N,Gen}$)	1– 20 kV
Transformer high voltage side rated voltage ($V_{N,THV}$)	11 – 220 kV
Generator rated power (S_N)	1– 150 MVA
Short circuit power level infeed at HV-side	500 – 10000 MVA

2.3.1.9 Two generators having one three-winding unit transformer, connected to a solidly grounded High Voltage (HV) system, with redundant protection with unit transformer differential protection

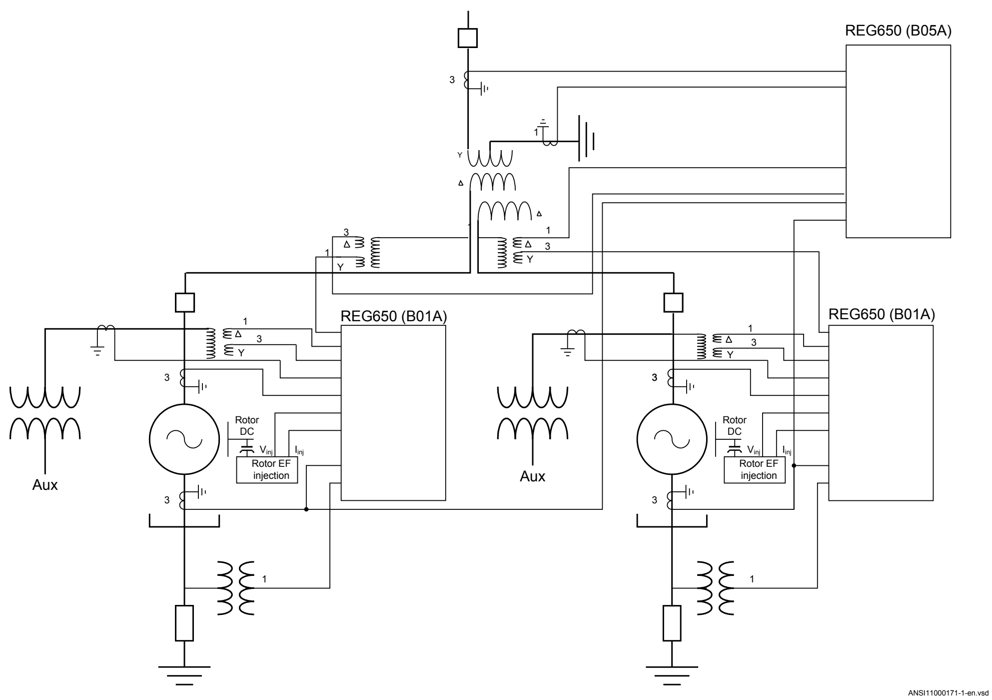


Figure 11: Two generators having one three-winding unit transformer, connected to a solidly grounded High Voltage (HV) system, with redundant protection with unit transformer differential protection

REG650 (B01A) is used as the main protection for the generator and REG650 (B05A) is used as the main protection for the unit transformer and as back-up protection for the generator. The combination of the protections also gives redundant protection for the auxiliary system transformer.

Table 9: Data for the generator application example

Parameter	Value
Generator rated voltage ($V_{N,Gen}$)	1– 20 kV
Transformer high voltage side rated voltage ($V_{N,THV}$)	11 – 220 kV
Generator rated power (S_N)	1– 150 MVA
Short circuit power level infeed at HV-side	500 – 10000 MVA

2.3.1.10 Functionality table

The proposal for functionality choice for the different application cases are shown in table 10.

The recommendations have the following meaning:

- Enabled: It is recommended to have the function activated in the application.
- Disabled: It is recommended to have the function deactivated in the application.
- Application dependent: The decision to have the function activated or not is dependent on the specific conditions in each case.

Application 5 — 8 in table10 are according to application examples given in previous sections.

Table 10: Recommended functions in the different application examples

Function	Application 5	Application 6	Application 7	Application 8
Generator differential protection GENPDIF (87G), (B01A)	Enabled	Enabled	Enabled	Enabled
Transformer differential protection T3WPDIF (87T), (B05A)	Enabled	Enabled	Enabled	Enabled
1Ph High impedance differential protection HZPDIF (87)	Application dependent	Application dependent	Application dependent	Application dependent
Underimpedance protection for generators and transformers ZGCPDIS (21G), (B01A)	Enabled	Enabled	Enabled	Enabled
Underimpedance protection for generators and transformers ZGCPDIS (21G), (B05A)	Disabled	Disabled	Disabled	Disabled
Load encroachment LEPDIS	Application dependent	Application dependent	Application dependent	Application dependent
Out-of-step protection OOSPPAM (78), (B01A)	Enabled	Enabled	Enabled	Enabled
Out-of-step protection OOSPPAM (78), (B05A)	Disabled	Disabled	Disabled	Disabled
Loss of excitation (underexcitation) protection LEXPDIS (40), (A01)	Enabled	Enabled	Enabled	Enabled

Table continues on next page

Function	Application 5	Application 6	Application 7	Application 8
Loss of excitation (underexcitation) protection LEXPDIS (40), (B05A)	Disabled	Disabled	Disabled	Disabled
Four step phase overcurrent protection OC4PTOC (51_67), instance 1 (B01A)	Enabled Aux T	Enabled Aux T	Enabled Aux T	Enabled Aux T
Four step phase overcurrent protection OC4PTOC (51_67), instance 1 (B05A)	Enabled	Enabled	Enabled	Enabled
Four step phase overcurrent protection OC4PTOC (51_67), instance 2	Disabled	Disabled	Disabled	Disabled
Four step residual overcurrent protection EF4PTOC (51N_67N), instance 1 (B01A)	Disabled	Disabled	Disabled	Disabled
Four step residual overcurrent protection EF4PTOC (51N_67N), instance 1 (B05A)	Enabled T HV	Enabled T HV	Enabled T HV	Enabled T HV
Four step residual overcurrent protection EF4PTOC (51N_67N), instance 2	Disabled	Disabled	Disabled	Disabled
Sensitive directional residual overcurrent and power protection SDEPSDE (67N), (B01A)	Enabled Rotor EF	Enabled Rotor EF	Enabled Rotor EF	Enabled Rotor EF
Sensitive directional residual overcurrent and power protection SDEPSDE (67N), (B05A)	Disabled	Disabled	Disabled	Disabled
Thermal overload protection TRPTTR (49), instance 1	Enabled	Enabled	Enabled	Enabled
Thermal overload protection TRPTTR (49), instance 2	Disabled	Disabled	Disabled	Disabled
Breaker failure protection CCRBRF (50BF), (B01A)	Enabled	Enabled	Enabled	Enabled
Breaker failure protection CCRBRF (50BF), (B05A)	Enabled HV CB	Enabled HV CB	Enabled HV CB	Enabled HV CB
Pole discordance protection CCRPLD (52PD)	Application dependent	Application dependent	Application dependent	Application dependent
Directional under-power protection GUPPDUP (37) (low forward power protection), (B01A)	1)	1)	1)	1)
Directional underpower protection GUPPDUP (37) (Low forward power protection), (B05A)	Disabled	Disabled	Disabled	Disabled
Directional overpower protection GOPPDOP (32), instance 1 (reverse power protection), (B01A)	1)	1)	1)	1)
Directional overpower protection GOPPDOP (32), instance 1 (reverse power protection), (B05A)	Disabled	Disabled	Disabled	Disabled
Directional overpower protection GOPPDOP (32), instance 2	Disabled	Disabled	Disabled	Disabled
Accidental energizing protection for synchronous generator AEGGAPC (50AE), (B01A)	Enabled	Enabled	Enabled	Enabled
Accidental energizing protection for synchronous generator AEGGAPC (50AE), (B05A)	Disabled	Disabled	Disabled	Disabled
Negative-sequence time overcurrent protection for machines NS2PTOC (46I2)	Enabled	Enabled	Enabled	Enabled
Voltage-restrained time overcurrent protection VR2PVOC (51V), (B01A)	2)	2)	2)	2)
Table continues on next page				

Function	Application 5	Application 6	Application 7	Application 8
Voltage-restrained time overcurrent protection VR2PVOC (51V), (B05A)	Disabled	Disabled	Disabled	Disabled
Two step undervoltage protection UV2PTUV (27), U<	Enabled	Enabled	Enabled	Enabled
Two step overvoltage protection OV2PTOV (59), U>	Enabled	Enabled	Enabled	Enabled
Two step residual overvoltage protection ROV2PTOV (59N), U0>, instance 1 (B01A)	Enabled Gen Neutr point	Enabled Gen Neutr point	Enabled Gen Neutr point	Enabled Gen Neutr point
Two step residual overvoltage protection ROV2PTOV (59N), U0>, instance 1 (B05A)	Enabled T sec side	Enabled T sec side	Enabled T sec side	Enabled T sec side
Two step Residual Overvoltage Protection ROV2PTOV (59N), U0>, instance 2 (B01A)	Enabled Gen Term	Enabled Gen Term	Enabled Gen Term	Enabled Gen Term
Two step residual overvoltage protection ROV2PTOV (59N), U0>, instance 2 (B05A)	Disabled	Enabled T HV neutr point	Enabled T sec side 2	Enabled T sec side 2
Overexcitation protection OEXPVPH (24)	Enabled	Enabled	Enabled	Enabled
100% Stator ground fault protection, 3rd harmonic based STEFPHIZ (59THD)/ 95 % fundamental based (B01A)	Enabled	Enabled	Enabled	Enabled
100% Stator ground fault protection, 3rd harmonic based STEFPHIZ (59THD)/ 95 % fundamental based (B05A)	Disabled	Disabled	Disabled	Disabled
Underfrequency protection SAPTUF (81), instance 1	Enabled	Enabled	Enabled	Enabled
Underfrequency protection SAPTUF (81), instance 2	Disabled	Disabled	Disabled	Disabled
Underfrequency protection SAPTUF (81), instance 3	Disabled	Disabled	Disabled	Disabled
Underfrequency protection SAPTUF (81), instance 4	Disabled	Disabled	Disabled	Disabled
Overfrequency protection SAPTOF (81), instance 1	Enabled	Enabled	Enabled	Enabled
Overfrequency protection SAPTOF (81), instance 2	Disabled	Disabled	Disabled	Disabled
Overfrequency protection SAPTOF (81), instance 3	Disabled	Disabled	Disabled	Disabled
Overfrequency protection SAPTOF (81), instance 4	Disabled	Disabled	Disabled	Disabled
Rate-of-change frequency protection SAPFRC (81), instance 1	Application dependent	Application dependent	Application dependent	Application dependent
Rate-of-change frequency protection SAPFRC (81), instance 2	Disabled	Disabled	Disabled	Disabled
Synchrocheck, energizing check, and synchronizing SESRSYN (25), (B01A)	Application dependent	Application dependent	Application dependent	Application dependent
Synchrocheck, energizing check, and synchronizing SESRSYN (25), (B05A)	Disabled	Disabled	Disabled	Disabled

1) The generator should have reverse power protection. If the generator consumes low reverse power at motor operation (< 1 % of S_N), low forward power protection should be used. In other cases, reverse power protection should be used.
2) Voltage-restrained time overcurrent protection add (VR2PVOC, 51V) can be used instead of the underimpedance protection.

Section 3 REG650 setting examples

The application example has a generation unit protected by one REG650 B01A (Main 1) and one REG650 B05A (Main 2) as shown in figure 12.

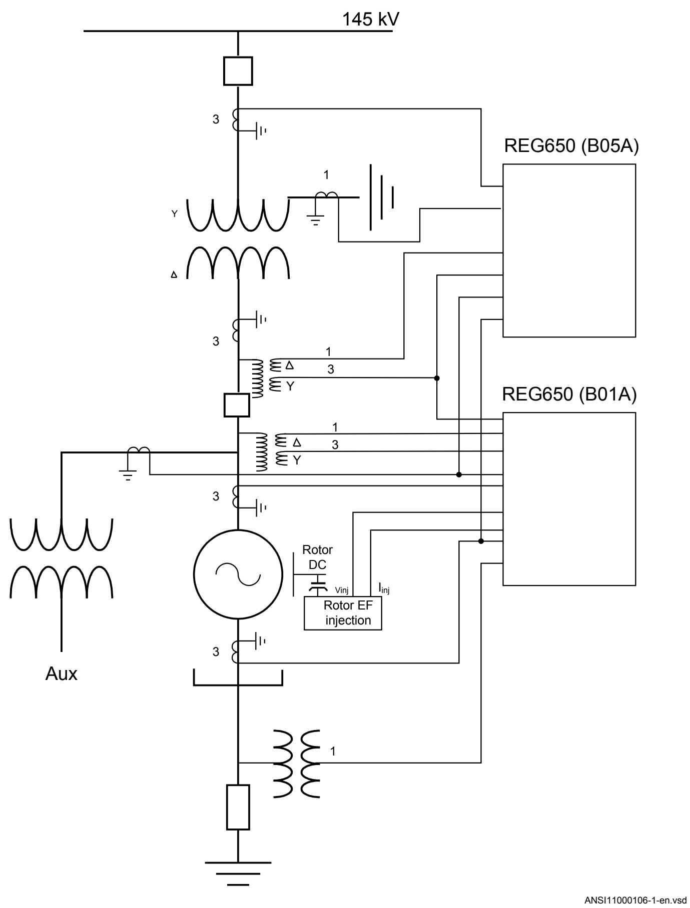


Figure 12: Power plant protection application

The following data is assumed:

Table 11: Data for the unit transformer

Item	Data
Transformer rated power S_N	25 MVA
Transformer high voltage side rated voltage V_{N1}	145 kV
Transformer low voltage side rated voltage V_{N2}	10.5 kV
Transformer vector group	YNd11
Transformer short circuit voltage e_k	12 %
Maximum allowed continuous overload	1.30 * S_N
Phase CT ratio at 145 kV level	150/1 A
CT at 145 kV ground point	150/1 A
Phase CT ratio at 10 kV level	1500/1 A
10 kV VT ratio	$\frac{11}{\sqrt{3}} / \frac{0.11}{\sqrt{3}} / \frac{0.11}{3} \text{kv}$
High Positive sequence source impedance at the HV side	10 ohm (about 2100 MVA) with a phase angle 85°
High Zero sequence source impedance at the HV side	j20 ohm

Table 12: Data for the generator

Item	Data
Generator rated power S_N	25 MVA
Generator rated voltage V_N	10.5 kV kV
Rate power factor $\cos\varphi_n$	0.90
x_d	1.0 per unit (pu)
x_d'	0.4 pu
x_d''	0.25 pu
Phase CT ratio at generator terminal side	1500/1 A
Phase CT ratio at generator neutral point side	1500/1 A
Generator neutral point VT ratio	$\frac{11}{\sqrt{3}} / 0.11 \text{ kV}$
Generator 10 kV terminal VT ratio	$\frac{11}{\sqrt{3}} / \frac{0.11}{\sqrt{3}} / \frac{0.11}{3} \text{kV}$

Table 13: Data for the auxiliary transformer

Item	Data
Transformer rated power S_N	1.0 MVA
Transformer high voltage side rated voltage V_{N1}	10.5 kV
Transformer low voltage side rated voltage V_{N2}	0.4 kV
Transformer vector group	Dyn5
Transformer short circuit voltage e_k	4 %
Phase CT ratio at 10.5 kV level	100/1 A

Only settings that need adjustment due to the specific application are described in setting examples. It is recommended to keep the default values for all settings that are not described. Refer to Technical manual for setting tables for each protection and control function.

Refer to setting guideline section in Application manual for guidelines on how to set functions that are not presented in setting examples.

Use parameter setting tool in PCM600 to set the IED according to calculations for the particular application.

3.1 Calculating general settings for analogue TRM inputs 4I 1I 5U

The transformer module (TRM) has the capability of 4 current inputs (tapped to 1 or 5 A), 1 current input (tapped to 0.1 or 0.5 A) and 5 voltage inputs.

The generator neutral point phase CTs (three-pole current transformer group) are connected to inputs 1 – 3 (A, B and C).

The generator neutral point CT can be connected to input 4 (not used here).

The rotor ground fault current measurement is connected to input 5.

The generator terminal side phase VT is connected to inputs 6 - 8 (A, B and C).

The generator neutral point VT is connected to input 9.

The rotor ground fault voltage measurement is connected to input 10.

1. Set the current transformer inputs.
   1.1. Set *CTStarPoint1* to *To Object*.
   The CT secondary is grounded towards the transformer.
   1.2. Set *CTSec1* to *1 A*.
   (The rated secondary current of the CT)
   1.3. Set *CTPrim1* to *1500 A*.
   (The rated primary current of the CT)
   1.4. Set the same values for current inputs 2 and 3.
   1.5. Set *CTStarPoint4* to —.
   1.6. Set *CTSec4* to —.
   1.7. Set *CTPrim4* to —.
   1.8. Set *CTStarPoint5* to *To Object*.
   1.9. Set *CTSec5* to *1 A*.
   1.10. Set *CTPrim5* to *1000 A*.
2. Set the voltage transformer inputs.
   2.1. Set *VTSec6* to *110 V*.
   (The rated secondary voltage of the VT, given as phase-to-phase voltage)
   2.2. Set *VTPrim6* to *11 kV*.
   (The rated secondary voltage of the VT, given as phase-to-phase voltage)
   2.3. Set the same values for current inputs 7 and 8.
   2.4. Set *VTSec9* to *110 V*.
   (The rated secondary voltage of the VT)
   2.5. Set *VTPrim9* to *6.35 kV*.
   This gives equivalent of ratio

   $$\frac{11}{\sqrt{3}} / 0.11 \text{ kV}$$

   2.6. Set *VTSec10* to *120 V*.
   2.7. Set *VTPrim10* to *120 kV*.

3.2 Calculating general settings for analogue AIM inputs 6I 4U

The analogue input module (AIM) has the capability of 6 current inputs (tapped to 1 or 5 A) and 4 voltage inputs.

The generator terminal side phase CTs (three-pole current transformer group) are connected to inputs 1 – 3 (A, B and C).

The auxiliary transformer 10 kV phase CTs (three-pole current transformer group) are connected to inputs 4 – 6 (A, B and C).

The transformer 10 kV phase VT is connected to inputs 7 - 9 (A, B and C).

The generator terminal side open delta VT is connected to input 10.

1. Set the current transformer inputs.
    1.1. Set *CTStarPoint1* to *To Object*.
    The CT secondary is grounded towards the transformer.
    1.2. Set *CTSec1* to *1 A*.
    (The rated secondary current of the CT)
    1.3. Set *CTPrim1* to *1500 A*.
    (The rated primary current of the CT)
    1.4. Set the same values for current inputs 2 and 3.
    1.5. Set *CTStarPoint4* to *To Object*.
    The CT secondary is grounded towards the bus transformer.
    1.6. Set *CTSec4* to *1 A*.
    (The rated secondary current of the CT)
    1.7. Set *CTPrim4* to *100 A*.
    (The rated primary current of the CT)
    1.8. Set the same values for current inputs 5 and 6.
2. Set the voltage transformer inputs.
    2.1. Set *VTSec7* to *110 V*
    (The rated secondary voltage of the VT, given as phase-to-phase voltage)
    2.2. Set *VTPrim7* to *11 kV*.
    (The rated secondary voltage of the VT, given as phase-to-phase voltage)
    2.3. Set the same values for current inputs 8 and 9.
3. Set *VTSec10* to *110 V*.
(The rated secondary voltage of the VT multiplied by 3)
4. Set *VTPrim10* to *19.05 kV*.
This gives equivalent of ratio

$$\frac{11}{\sqrt{3}} / \frac{0.11}{3} \text{kv}$$

3.3 Preprocessing blocks SMAI

Many of the protection functions must be enabled to operate also during generator run-up, i.e. in circumstances where the frequency of the non-synchronized generator deviates from the rated frequency. Therefore, the function of the pre-processor blocks is achieved using frequency adapted Fourier filtering. Adaptive frequency tracking must be properly configured and set for the signal matrix for analogue inputs (SMAI) pre-processing blocks in order to ensure proper operation of the generator differential protection function and other protection functions.

The generator voltage should be the reference of the frequency adapted Fourier filtering. Therefore, the generator terminal voltage is linked to the blocks SMAI_20_1 in the 5 and 20 ms pre-processor groups.

1. Set *DFTReference* to *DFTRefGrp1* in SMAI_20_1:1, 5 ms.
   This instance is the reference of the Fourier filtering.
2. Set *DFTRefExtOut* to *DFTRefGrp1* in SMAI_20_1:1, 5 ms.
   This instance is the reference for the signal sent out on output SPFCOUT. The signal is configured to the SMAI_20_1 in the 20 ms pre-processor group, input DFTSPFC.
3. Set *DFTReference* to *ExternalDFTref* in SMAI_20_1:2, 20 ms.
   The input DFTSPFC is the reference of the Fourier filtering.
4. Set *DFTRefExtOut* to *ExternalDFTRef* in SMAI_20_1:2, 20 ms.
   No output from this pre-processor block is configured.
5. Set *DFTReference* to *DFTRefGrp1* for all the pre-processor blocks in the 5 ms group.
6. Set *DFTReference* to *ExternalDFTRef* for the pre-processor blocks in the 20 ms group. This is the same as the signal configured for the input of group 1.
7. Set *DFTReference* to *InternalDFTRef* for the pre-processor blocks SMAI_20_6:2 and SMAI_20_7:2 (20 ms), as the frequency is equal to the injected fundamental frequency voltage.

3.4 Calculating settings for global base values for setting function GBASVAL

Each function uses primary base values for reference of settings. The base values are defined in Global base values for settings function. It is possible to include six Global base values for settings GBASVAL functions: global base 1 – global base 6.

Global base 1 is used for defining the base for generator protections, Global base 2 for step-up transformer HV-side protections, Global base 3 for auxiliary transformer HV-side protections, Global base 4 for excitation transformer HV-side protections, Global base 5 for rotor ground fault protections and Global base 6 for generator zero-sequence based protections.

At delivery, following base values are used:

Global Base	IBase [A]	VBase [kV]	SBase [MVA]
1	1522	11.00	29.000
2	138	121.00	29.000
3	84	11.00	1.600
4	20	11.00	0.390
5	1000	100.00	29.000
6	200 1)	33.00 2)	29.000

1) Primary rating of CT-G connected to free ground-fault protection function in order to use it as turn-to-turn protection
2) 3x11=33kV. Used for residual overvoltage protections which measure 3Uo voltage

These global base values shall be changed in accordance with the application in which REG650 is actually installed.

3.5 Calculating settings for generator differential protection GENPDIF (87G)

1. Set *GlobalBaseSel* to *1*.
2. Set *Operation* to *Enabled*.
3. Set *EndSection1* to *1.25 IBase*.
4. Set *EndSection2* to *3 IBase*.
5. Set *SlopeSection2* to *40 %*.

6. Set *SlopeSection3* to *80 %*.
   The characteristic of the restrained and unrestrained differential protection is shown in figure 13. The differential current limit for the operation of the protection is shown as a function of the restrain current. In REG650, the restrain current is equal to the highest generator phase current. The restrain characteristic is defined by the parameters: *IdMin*, *EndSection1*, *EndSection2*, *SlopeSection2* and *SlopeSection3*. The settings of *EndSection1*, *EndSection2*, *SlopeSection2* and *SlopeSection3* are defined as advanced and the default values are recommended.

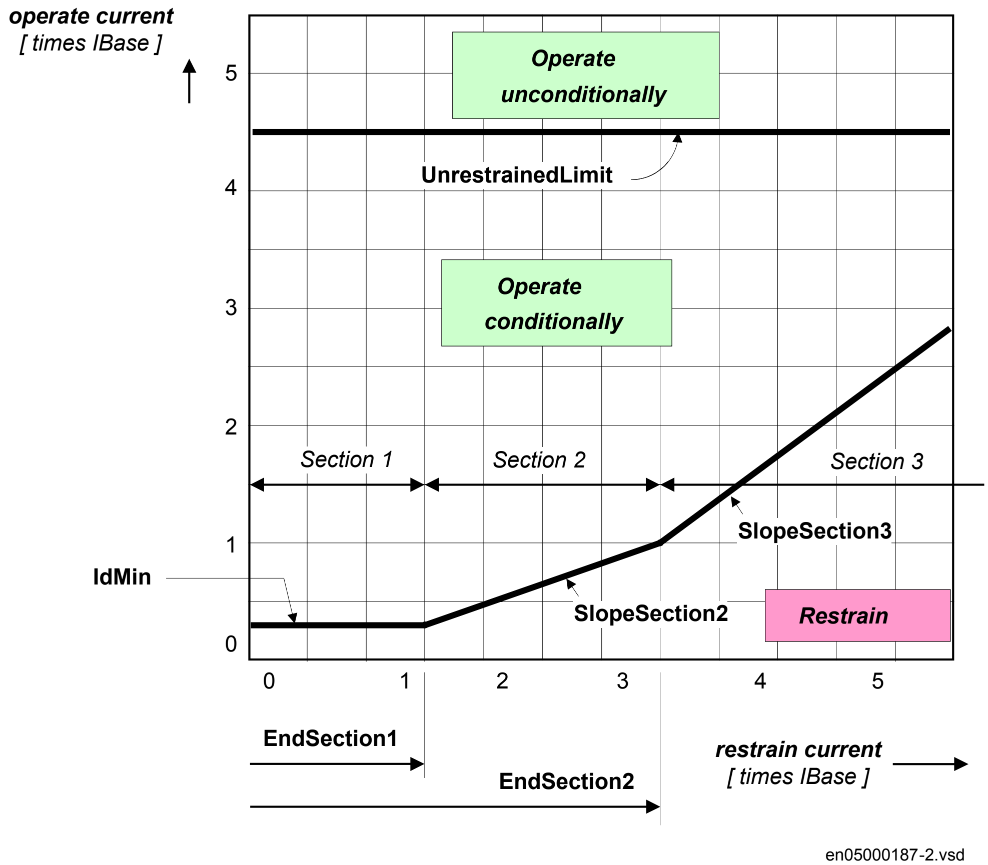


Figure 13: Generator differential protection operation characteristic

During normal operation, there is a ”false” differential current measured by the protection due to difference in current transformer error. The current transformer class C gives a maximum amplitude error of 1 % and maximum phase displacement of 60 minutes.

7. Set *IdMin* to *0.10 IBase*.
   IdMin is set to 0.10 pu of the rated generator current to assure that the load current will not cause unwanted operation.
8. Set *IdUnre* to *6.0 IBase*.

The unrestrained differential protection function operates without stabilization. The setting principle is that the unrestrained function shall only be able to detect internal faults. This means that the current setting shall be (*IdUnre*) higher than the highest current through the generator at external faults. A very simple way to estimate this current is:

$$IdUnre \geq \frac{1}{x_d''} \cdot I_{N,generator} = \frac{1}{0.25} \cdot I_{N,generator} = 4 \cdot I_{N,generator}$$

The influence of fault current DC-component should be considered in the setting.

9. Set *OpNegSeqDiff* to *Yes*.
10. Set *IMinNegSeq* to *0.04 IBase*.
11. Set *NegSeqROA* to *60°*.
    The genertor differential protection also has external/internal fault discrimination, based on negative sequence current. The settings of *OpNegSeqDiff*, *IMinNegSeq* and *NegSeqROA* are defined as advanced and the default values are recommended.
12. Set *OpCrossBlock* to *Yes*.
    If the harmonic restrain function is activated in one phase, cross-blocking can be used to prevent operation of the differential protection also in other phases.

3.6 Calculating settings for underimpedance protection for generators and transformers ZGCPDIS 21G

Underimpedance function shall be set for the application example shown for REG650 (B05A) with assumption that the step-up transformer impedance is 10%. See Figure 3 the step-up transformer impedance in primary ohms on generator side is calculated as:

$$X_T = \frac{x_t}{100} \cdot \frac{V_r^2}{S_T} = \frac{10}{100} \cdot \frac{11^2}{29} = 0.4172\Omega$$

(Equation 1)

Rated generator load impedance can be calculated as follows:

$$Z_{Load} = \frac{V_G^2}{S_G} = \frac{11^2}{29} = 4.1724\Omega$$

(Equation 2)

This impedance represents measured impedance by ZGCPDIS (21G) function when generator is at rated load.

For load encroachment setting calculation it is assumed that the generator's rated power factor is Grated_PF =0.8. This data is available on the generator rating plate.

3.6.1 Calculating settings for zone 1

Impedance stage Zone 1 is set to reach only into the step-up transformer (that is, it will never over-reach through the transformer) and will provide a fast back-up protection for phase short-circuits on the generator terminals, the generator bus and the low voltage winding of the unit transformer. It should be observed that with this low setting, the function will also protect a part of the stator winding.

Thus, Zone 1 is set to 75% of the step-up transformer impedance. Typically no time delay or very short time delay is used (for example, 0-100ms) when coordination with the generator stator differential function is required. To get such coverage set the following for this application:

1. Set *Operation* to *Enabled* to enable ZGCPDIS.(21)
2. Set *ImpedanceAng* to 80 degrees. *ImpedanceAng* is common for all three zones.
3. Set *OpModeZ1* to *Enabled* to enable zone 1.
4. Set *Z1Fwd* to 0.313 Ohms. *Z1Fwd* $=0.75 \cdot X_T = 0.75 \cdot 0.4172 = 0.313$ Ohms.
5. Set *Z1Rev* to 0.313 Ohms. *Z1Rev* $=0.75 \cdot X_T = 0.75 \cdot 0.4172 = 0.313$ Ohms.
6. Set zone 1 time delay *tZ1* to 0.100 s.

3.6.2 Calculating settings for zone 2

Zone 2 is set to 125% of the step-up transformer impedance (that is, it will always over-reach through the transformer in order to protect the HV busbars). It protects the whole transformer and the HV busbars. Time delay is required to coordinate with the HV line distance protection Zone 1 operation and eventual HV breaker failure protection.

> The reverse reach must be limited to 100% of the transformer impedance in order to avoid problems during loss-of-excitation condition and for power swings.

To get such coverage for this application:

1. Set *OpModeZ2* to *Enabled* to enable zone 2.
2. Set *Z2Fwd* to 0.522 Ohms. *Z2Fwd* $=1.25 \cdot X_T = 1.25 \cdot 0.4172 = 0.522$ Ohms.
3. Set *Z2Rev* to 0.4172 Ohms. *Z2Rev* $=1.0 \cdot X_T = 1.0 \cdot 0.4172 = 0.4172$ Ohms.
4. Set zone 2 time delay *tZ2*=0.300 s.

3.6.3 Calculating settings for zone 3

Impedance stage Zone 3 can be normally set to operate for up to 70 % of rated generator load impedance, corresponding to an operate current of 1/0.7=1.43 times rated current at rated voltage. This will provide sensitive backup short-circuit protection for faults in the HV network. The selectivity against other distance IEDs in the HV network has to be secured by a proper time delay setting.

The reverse reach must be limited to the same value as for Zone 2 due to the same reasons.

To get such coverage for this application:

1. Set *OpModeZ3* to *Enabled* to enable zone 3.
2. Set *Z3Fwd* to 2.921 Ohms. *Z3Fwd* =0.70 · ZLoad = 0.70 · 4.1724=2.921 Ohms.
3. Set *Z3Rev* to 0.4172 Ohms. *Z3Rev* =1.0 · ZLoad = 1.0 · 4.172=0.4172 Ohms.
4. Set *tZ3* to 3.000 s. Zone time delay must be coordinated against time delays used for the HV line distance protection Zone 3 or Zone 4.
5. Set *LoadEnchModZ3* to *Enabled*. For such large forward reach it is recommended to enable the load encroachment feature.

3.6.4 Calculating settings for the Load encroachment function

Load encroachment (LEPDIS), function can only shape the Zone 3 characteristic of the ZGCPDIS (21) function according to Figure 14. The load encroachment feature is used to prevent unwanted operation of the underimpedance function during special operating conditions in the HV network (for example heavy loads, fault clearing, system disturbances, power swing).

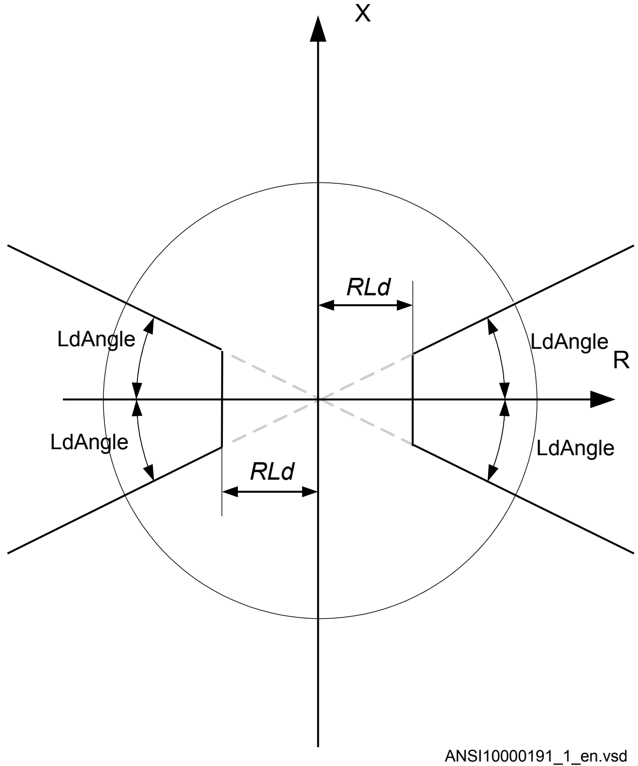


Figure 14: Zone 3 characteristic with enabled Load encroachment for offset mho underimpedance function ZGCPDIS (21)

The main settings of the parameters for load encroachment are done in LEPDIS function.

Setting *LoadEnchModZ3* for Zone 3 in ZGCPDIS (21) function must be set to *Enabled* to enable the load encroachment feature.

For load encroachment for generator application the simplest way is to follow the IEEE recommendation given in the IEEE PSRC WG Report "Performance of Generator Protection During Major System Disturbances" which suggest that generator shall be capable to operate at 200% of the machine MVA rating at the machine's rated power factor. In the impedance operating plane this means at 50% of the rated generator load impedance at angle corresponding to acos(Grated_PF).

Thus in order to get this set the following for this application:

1. Set *RLd* to 1.669 Ohms. *RLd* =Grated_PF · 0.5 · ZLoad=0.8 · 0.5 · 4.1724=1.669 Ohms.
2. Set *LdAngle* to 37 degrees. *LdAngle* = acos(Grated_PF)=acos(0.8)=37 degrees.

3.7 Calculating settings for out-of-step protection OOSPPAM (78)

The setting impedance values are given in % of *ZBase*. *ZBase* is defined as:

$$ZBase = \frac{VBase/\sqrt{3}}{IBase} = \frac{VBase^2}{SBase}$$

The parameters *VBase* and *SBase* are given in the Global Base setting and are normally set to the generator rated voltage (phase-to-phase) in kV and to the generator rated apparent power in MVA.

In this case:

$$ZBase = \frac{10.5^2}{25} = 4.41\ \Omega$$

The generator and the power system can be described as shown in figure 15.

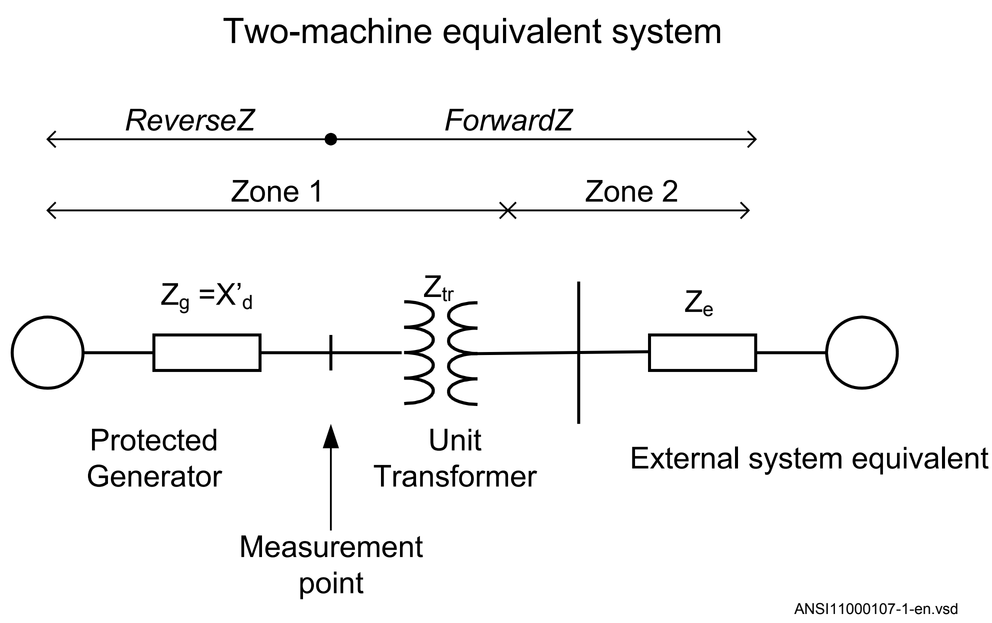


Figure 15: Equivalent of generator unit and external power system

The impedance settings define the characteristic of the out-of-step protection as shown in the impedance diagram in figure 16.

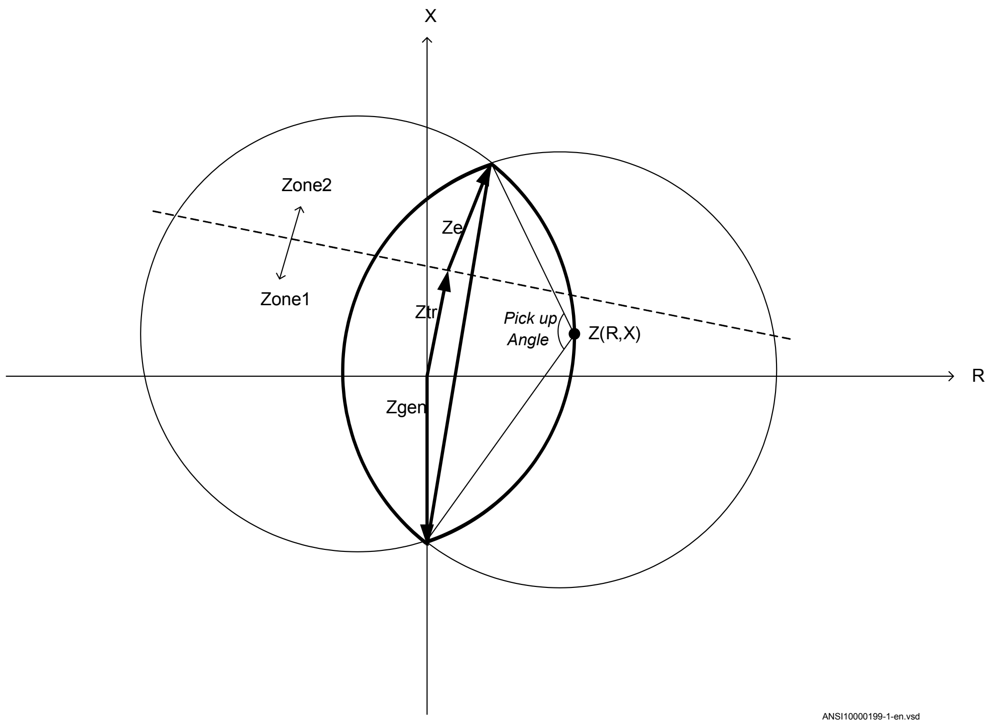


Figure 16: Impedance characteristic of the out-of-step protection

The forward impedance is divided into resistive and reactive parts *ForwardR* and *ForwardX*. The forward impedance is the sum of the unit transformer impedance and the external system equivalent source impedance. The unit transformer impedance can be calculated from the transformer data:

$$X_{tr} = \frac{V_N^2}{S_N} \cdot v_{sc} = \frac{10.5^2}{25} \cdot 0.12 = 0.53\ \Omega$$

or 12 % of *ZBase*.

This reactance is calculated as ohms with rated voltage V_N at the generator side of the transformer. S_N is the rated apparent power of the transformer and v_{sc} is the short circuit voltage of the transformer given in pu.

$$R_{tr} = \frac{V_N^2}{S_N} \cdot r_{sc}$$

The transformer resistance is normally negligible compared to the transformer reactance and is therefore set to 0 in this case.

The impedance of the external system can be calculated by means of short circuit calculation. At a three-phase short circuit on the high voltage side of the unit transformer, the short circuit current from the system is I_{sc}. As the largest risk for out-of-step conditions occurs when the system is weak, should the calculation be made at such weak conditions. A typical case is when one line to the power plant is tripped. The external complex system impedance referred to the high voltage side of the unit transformer, can be estimated:

$$Z_{e,HV} = R_{e,HV} + jX_{e,HV} = \frac{V_{net}/\sqrt{3}}{I_{sc}}$$

The impedance is given to Ze, HV = 0,87 + j10 Ω on 145 kV level.

As this impedance is calculated at the high voltage side of the unit transformer this impedance must be transformed to the generator side of the unit transformer:

$$Z_{e,LV} = R_{e,LV} + jX_{e,LV} = Z_{e,HV} \cdot \left(\frac{V_{N,LV}}{V_{N,HV}}\right)^2 = 0.87 + j10.00 \cdot \left(\frac{10.5}{145}\right)^2 = 0.0046 + j0.0524\ \Omega$$

The forward impedance can now be given:

$$ForwardR = \left(R_{tr} + R_{e,LV}\right) \cdot \frac{100}{ZBase}\,\% = \left(0.00 + 0.0046\right) \cdot \frac{100}{4.41} = 0.10\,\%$$

$$ForwardX = \left(X_{tr} + X_{e,LV}\right) \cdot \frac{100}{ZBase}\,\% = \left(0.53 + 0.052\right) \cdot \frac{100}{4.41} = 13.2\,\%$$

The reverse impedance is divided into resistive and reactive parts, *ReverseR* and *ReverseX*. The reverse impedance is the impedance of the generator. As the out-of-step phenomenon occurs slowly compared to short circuit, it is appropriate to use the generator transient reactance for the setting. If the base impedance *ZBase* is based on the generator rated data the settings can be given directly:

$$ReverseR = r_{g,pu} \cdot 100\,\% = 0$$

$$ReverseX = x_d' \cdot 100\,\% = 40\,\%$$

*ReachZ1*defined the reach of zone 1 in the forward direction. Zone 1 should reach through the unit transformer but not further. The setting is given in % of *ForwardX*.

$$ReachZ1 = \frac{X_{tr}}{X_{tr} + X_{e,LV}} \cdot 100\,\% = \frac{0.53}{0.53 + 0.052} = 91\,\%$$

The apparent impedance enters the lens characteristic as shown in figure 17 when the rotor angle gets larger than the set *pick up Angle*.

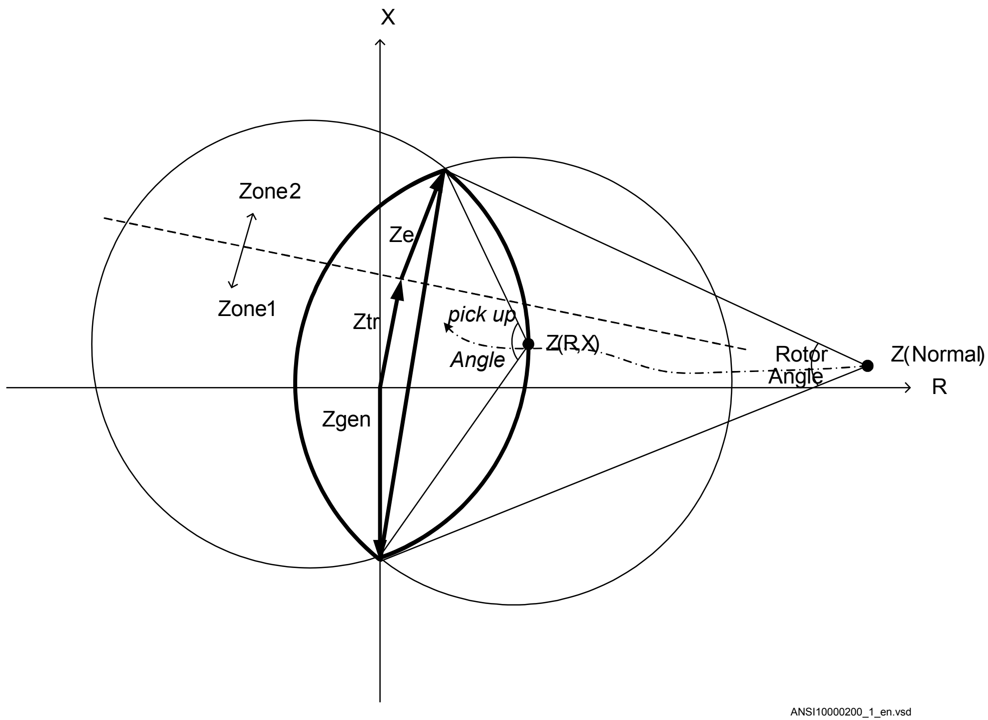


Figure 17: Locus of the apparent impedance at start angle

The default value 110° for *pick up Angle* is recommended.

To avoid severe stress on the circuit breaker when it is to be tripped due to pole slip, the trip signal is delayed until the rotor angle gets smaller than the set value of *TripAngle* as shown in figure 18.

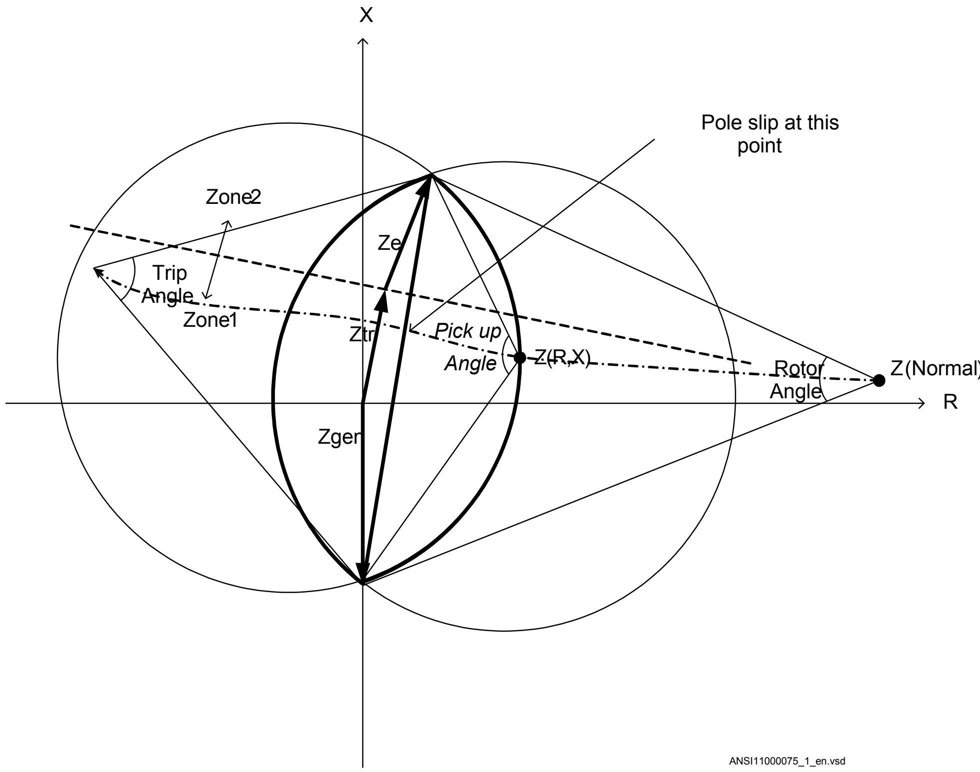


Figure 18: Locus of the apparent impedance at pole slip and TripAngle

The default setting value of *TripAngle* is 60° is recommended.

tReset is the time interval since the last pole-slip to reset the out-of-step function. The default setting 6.0 s is recommended.

NoOfSlipsZ1 is the number of pole slips in zone 1 required for zone 1 trip. Normally, the trip should be made as fast as possible to minimize the impact on the unit caused by pole slip. The default setting 1 (trip at first pole slip) is strongly recommended.

NoOfSlipsZ2 is the number of pole slips in zone 2 required for zone 2 trip. If the centre of the out-of-step condition is in the network the apparent impedance at the pole slip moment is within zone 2. In such a case, it is preferable that the network is split into two parts where the two islands have all generators still connected and in operation. Therefore, the pole slip protection should allow the network separation without trip of the generator CB.

NoOfSlipsZ2 should be set at least to the value 2 (trip after second pole slip).

OperationZ1 can be set *Enabled* or *Disabled* and should be set *Enabled* to allow trip for pole slip within zone 1.

OperationZ2 can be set *Enabled* or *Disabled* and should be set *Enabled* to allow trip for pole slip within zone 2.

tBreaker specifies the opening time of the circuit breaker. If it is set larger than 0 the *TripAngle* setting is ignored and a more advanced method is used to send the trip signal at the most favourable moment for the circuit breaker. A typical value of *tBreaker* is 0.040 s.

3.8 Calculating settings for loss of excitation LEXPDIS (40)

The setting impedance values are given in % of *ZBase*. *ZBase* is defined as:

$$ZBase = \frac{VBase/\sqrt{3}}{IBase} = \frac{VBase^2}{SBase}$$

The parameters *VBase* and *SBase* are given in the Global Base setting and are normally set to the generator rated voltage (phase-to-phase) in kV and to the generator rated apparent power in MVA.

In this case:

$$ZBase = \frac{10.5^2}{25} = 4.41\,\Omega$$

The setting with two activated zones of the protection is described here. Zone Z1 gives a fast trip if the dynamic limitation of the stability is reached. Zone 2 gives a trip after a longer delay if the generator reaches the static limitation of stability. A restrain area is also used to prevent trip at close in external faults in case the zones reach the impedance area as shown in figure 19.

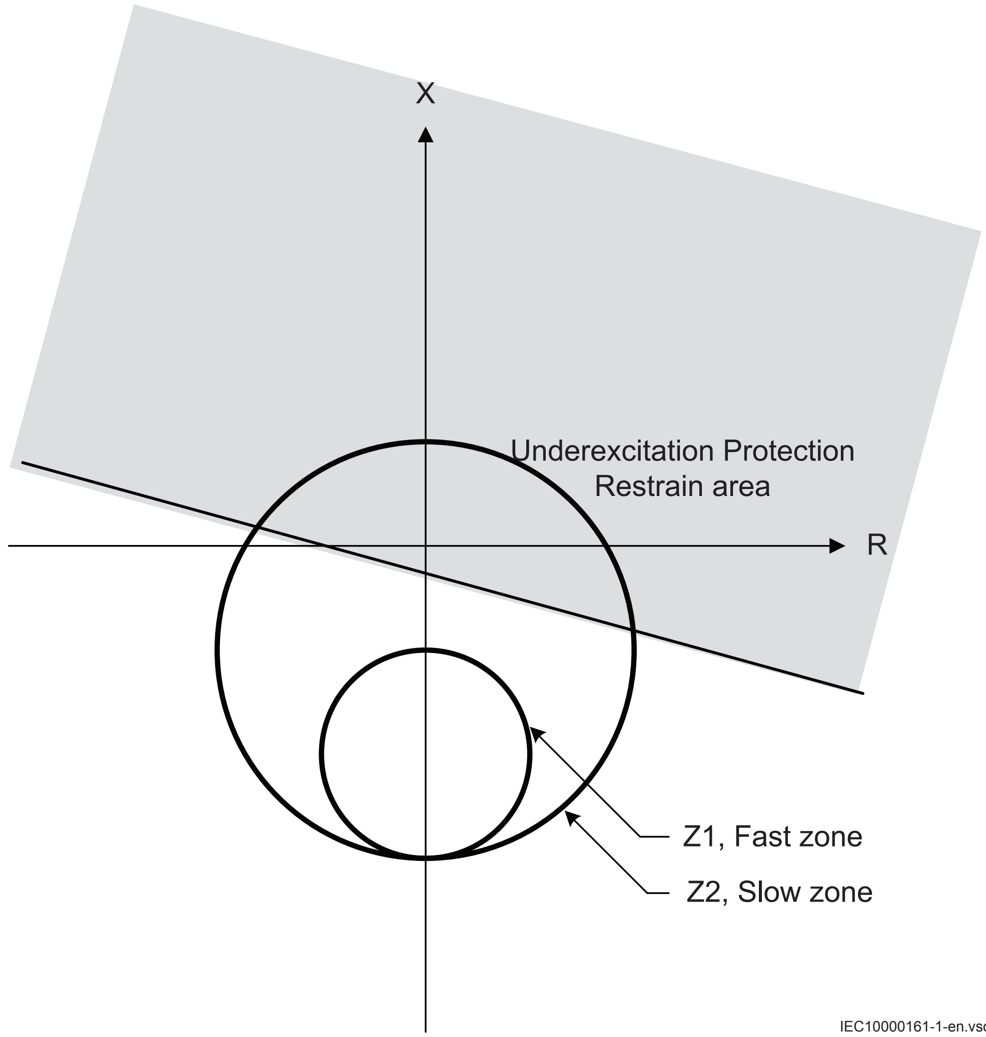


Figure 19: Characteristics of the under-excitation protection

1. Set *Operation* to *Enabled*.
2. *OperationZ1* and *OperationZ2* to *Enabled*
   For the two zones the impedance settings are made as shown in figure 20.

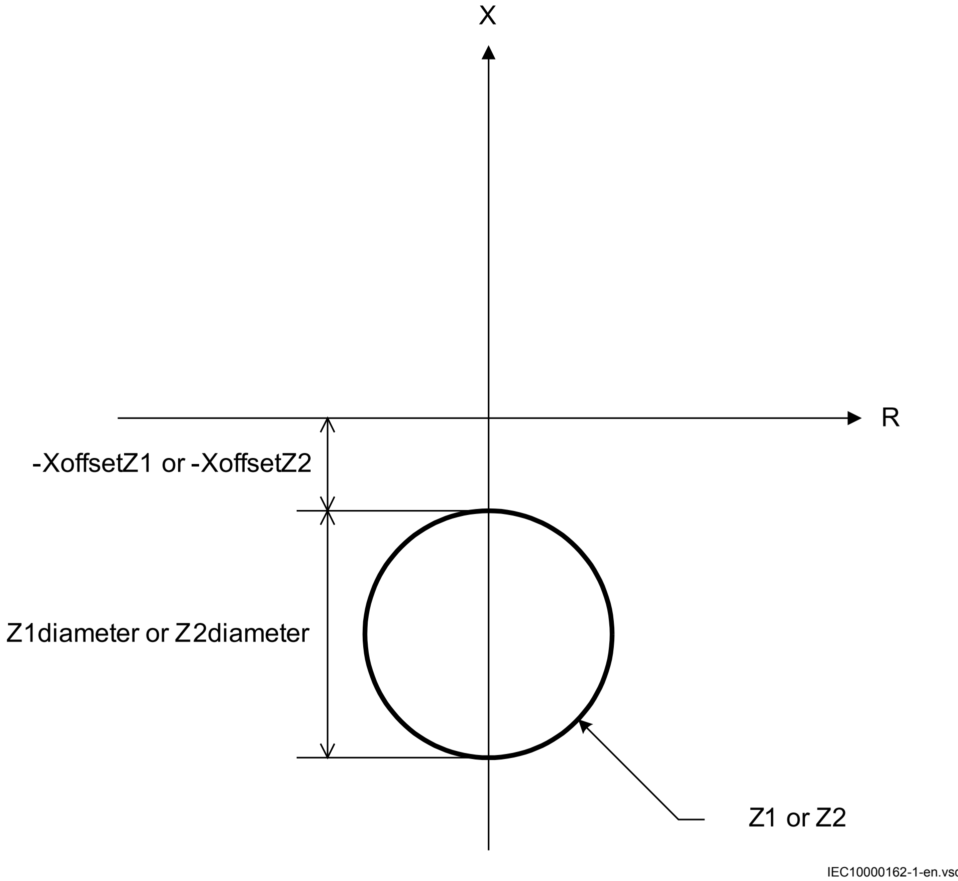


Figure 20: Impedance setting parameters for the under-excitation zones 1 and 2

XOffsetZ1 and *XOffsetZ2*, offset of impedance circle top along the X axis, are given negative value if X < 0.
It is recommended to set *XOffsetZ1* equal to

$$-X'_d/2 = -\frac{0.4}{2} \cdot 100\,\% = -20.0\,\%$$

and *Z1diameter*, including 10 % safety factor, equal to

$$1.1 \cdot X_d - X'_d/2 = (1.1 \cdot 1.0 - \frac{0.4}{2}) \cdot 100\,\% = 90\,\%$$

tZ1 is the setting of trip delay for Z1 and it is recommended to set it to 0.1 s. It is recommended to set *XOffsetZ2* equal to $-X_e = -\frac{0.052}{4.41} \cdot 100\,\% = -1.1\,\%$ (the equivalent impedance of the external network) and *Z2diamater* equal to

$$1.1 \cdot X_d + X_e = (1.1 \cdot 1 \cdot 4.41 + 0.052) \cdot \frac{100}{4.41}\,\% = 111\,\%$$

tZ2 is the setting of trip delay for Z2 and this parameter is recommended to set to 2.0 s to avoid risk of unwanted trip at oscillations with temporary apparent impedance within the characteristic.

3. Set *DirSuperv* to *Enabled*.
   The directional restrain characteristic allows impedance setting with positive X value without the risk of unwanted operation of the under-excitation function. To enable the directional restrain option the parameter *DirSuperv* shall be set *Enabled*.
   The parameters *XoffsetDirLine* and *DirAngle* are shown in figure 20.
   XoffsetDirLine is set in pu of the base impedance. *XoffsetDirLine* is given a positive value if X > 0. The default setting 0.0 % is recommended.
   DirAngle is set in degrees with negative value in the 4th quadrant. The default setting – 13° is recommended.

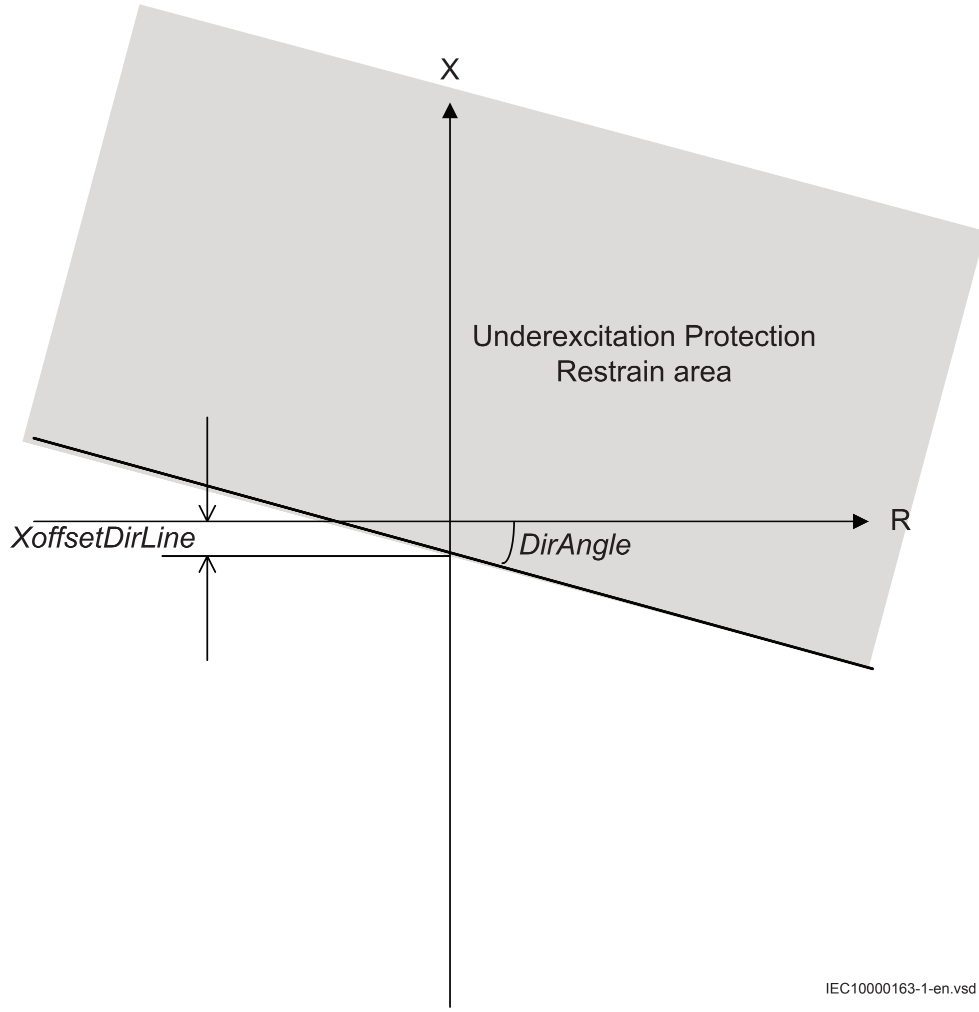


Figure 21: Directional restrain characteristic

3.9 Negative-sequence time overcurrent protection for machines NS2PTOC (46I2)

Negative-sequence time overcurrent protection for machines (NS2PTOC, 46I2) function is mainly recommended if the substation is close to a power plant. The setting is dependent of the negative sequence withstand capacity of connected objects. A general setting is not given.

3.10 Calculating settings for four step phase overcurrent protection 3-phase output OC4PTOC (51_67)

3.10.1 Calculating settings for generator phase overcurrent protection

The generator phase overcurrent protection is fed from the CTs on the terminal side of the generator. It will therefore detect fault current from the external network for generator faults and fault current from the generator for faults in the unit transformer or in the external network.

The phase overcurrent protection has the following tasks:

- Backup for generator stator short circuits
- Backup protection for short circuits in the unit transformer

It should be observed that the short circuit current from the generator, at fault in the transformer or in the external system, will decrease during the fault sequence. This is due to increasing generator reactance and decreased excitation as the excitation system is fed from the generator terminal voltage. The reach of the generator phase overcurrent protection might be insufficient for detection of external short circuits.

The protection uses two steps. The requirement is that short circuits in the generator and some of the short circuits within the unit transformer shall be tripped in a short time (zone 1). The slower zone 2, with a longer trip time shall detect short circuits on the high voltage side of the unit transformer with some margin.

3.10.1.1 Calculating settings for step 1

1. Set *GlobalBaseSel* to 1.
2. Set *DirModeSel1* to *Non-directional*.
3. Set *Characteristic1* to *IEC Def. Time*.
4. Set *Pickup1* to *330 %* of *IBase* (4.6 kA).
   At three phase short circuit on the unit transformer high voltage side, the generator fault current *Isc* is 3.7 kA. The setting of step 1 is therefore chosen to: *Pickup1*: 4.5 kA corresponding to about 330 % of *IBase*.
5. Set *t1* to *0.3 s*.

3.10.1.2 Calculating settings for step 2

The first requirement of step 2 is that the maximum load current shall not give unwanted trip. Temporary overload of 50 % is assumed. The reset ratio of the phase overcurrent protection is 95 %:

$$I2> \geq \frac{1{,}5 \cdot 1375}{0{,}95} \approx 2171\ A$$

At two-pole short circuit on the unit transformer high voltage side, the generator fault current is: Isc = 3.7 kA (in one phase due to vector group YNd11). Therefore:

$$I2> \leq 0.7 \cdot 3700 = 2590\ A$$

In case of a three-pole short circuit 80 % (distance protection zone 1 reach) out on the shortest line out from the power plant the generator current is less than 2000 A.

1. Set *DirModeSel2* to *Non-directional*.
2. Set *Characteristic2* to *IEC Def. Time*.
3. Set *Pickup2* to *170 %* of IBase (2.3 kA).
4. Set *t2* to *0.5 s*.

3.10.2 Calculating settings for auxiliary transformer phase overcurrent protection

The auxiliary transformer phase overcurrent protection is fed from the CTs on the high voltage side of the transformer.

The phase overcurrent protection has the following tasks:

- Main protection for short circuits in the auxiliary transformer
- Backup protection for short circuits in auxiliary low voltage system

The protection uses two steps. The requirement is that high current short circuits within the transformer shall be tripped instantaneously (step 1). The slower step 4, with a trip time coordinated with the low voltage protections (fuses) shall detect short circuits on the low voltage side of the auxiliary transformer with some margin. Step 4 is used as it allows inverse time characteristic.

3.10.2.1 Calculating settings for step 1

1. Set *GlobalBaseSel* to 3.
2. Set *DirModeSel1* to *Non-directional*.
3. Set *Characteristic1* to *IEC Def. Time*.
4. Set *Pickup1* to *100 %* of *IBase* (1.7 kA).
   In case of a three-phase short circuit on the auxiliary transformer low voltage side, the fault current on the 10.5 kV level is: I_{sc} = 1.3 kA. *Pickup1* is therefore set to *1.7 kA* corresponding to about 100 % of *IBase*.
5. Set *t1* to *0.0 s*.

3.10.2.2 Calculating settings for step 4

The first requirement of step 4 is that the maximum load current shall not give an unwanted trip. Temporary overload of 50 % is assumed. The reset ratio of the phase overcurrent protection is 95 %:

$$I4 > \geq \frac{1,5 \cdot 55}{0,95} = 87\ A$$

At two-phase short circuit on the unit transformer low voltage side, the generator fault current is: I_{sc} = 1.3 kA (in one phase due to vector group Dyn). Therefore:

$$I4 > \leq 0.7 \cdot 1300 = 910\ A$$

The time coordination shall assure selectivity to fuses at the low voltage side. With a setting *Pickup4* of 150 A the selectivity to a LV fuse of 1600 A will be according to figure 22.

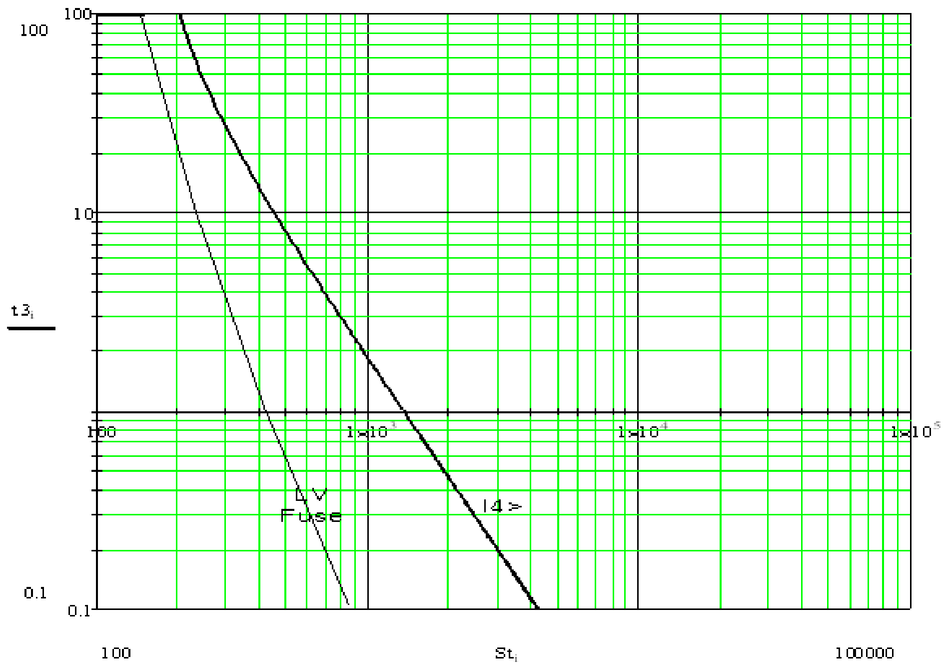


Figure 22: Phase overcurrent selectivity

1. Set *DirModeSel4* to *Non-directional*.
2. Set *Characteristic4* to *IEC Ext. inv.* .
3. Set *Pickup4* to *50 %* of *IBase* (650 A).
4. Set *TD4* to *1.0*.

3.11 100% Stator ground fault protection, 3rd harmonic based STEFPHIZ 59TDH

The 3rd harmonic based 100 % stator ground fault protection uses the 3rd harmonic voltage generated by the generator. To assure reliable function of the protection, it is necessary that the 3rd harmonic voltage generation is at least 1 % of the generator rated voltage.

1. Set *GlobalBaseSel* to 1.
2. Set *Operation* to *Enabled*.
3. Set *TVoltType* to *AllThreePhasesl*.
   The protection function is always fed from a voltage transformer in the generator neutral. *TVoltType* defines how the protection function is fed from voltage transformers at the high voltage side of the generator. The setting alternatives are:
   - *NoVoltage* which is used when there are no voltage transformers connected to the generator terminals. In this case, the protection will operate as a 3rd harmonic undervoltage protection.
   - *ResidualVoltage* which is used if the protection is fed from an open delta connected three-phase group of voltage transformers connected to the generator terminals.
   - *AllThreePhases* is used when the protection is fed from the three-phase voltage transformers. The third harmonic residual voltage is derived internally from the phase voltages.
   - OneSinglePhaseVoltage(*PhaseA*, *PhaseB*, *PhaseC*) is used when there is only one phase voltage transformer available at the generator terminals.
4. Set *Beta* so that DV3/BV3 < 0.5 there DU3 and BU3 are measured values, in non-faulty conditions and generator connected to the grid.
   The setting *Beta* gives the proportion of the 3rd harmonic voltage in the neutral point of the generator to be used as restrain quantity. *Beta* must be set so that there is not risk of trip during normal, non-faulty operation of the generator. On the other hand, if *Beta* is set high, it limits the portion of the stator winding covered by the protection. The default setting 3.0 will in most cases give acceptable conditions. One possibility to assure best performance is to perform measurements during normal operation of the generator (at commissioning). From the function, the following quantities are available:
   - VT3, the 3rd harmonic voltage at the generator terminal side
   - VN3, the 3rd harmonic voltage at the generator neutral side
   - E3, the induced 3rd harmonic voltage
   - ANGLE, the phase angle between VT3 and VN3
   - DV3, the differential voltage caused by VT3 and VN3 (VT3 + VN3)
   - BV3, the bias voltage (beta VN3)

   For different operation points (P and Q) of the generator, the differential voltage DV3 can be compared to the bias BV3, and a suitable factor *beta* can be chosen to assure security.
5. Set *CBexists* to *Yes* as the generator breaker exists (breaker between the generator and the block transformer).
   In such a case, the setting *FactorCBopen* is activated.
6. Set *FactorCBopen* so that DU3/BU3 < 1 in non-faulted conditions and generator not connected to the grid.

The setting *FactorCBopen* gives a constant to be multiplied to *Beta* if the generator circuit breaker is open. This factor should also be set during commissioning.

7. Set *VNFundPU* to *5 %* (95 % stator ground fault protection).
   VNFundPU gives the operation level for the fundamental frequency residual voltage stator ground fault protection. The setting is given as % of the rated phase-to-ground voltage. A normal setting is in the range 5 – 10 %.
8. Set *t3rdH* to *10 s*.
   t3rdH gives the trip delay of the 3rd harmonic stator ground fault protection.
9. Set *tFund* to *1.0 s*.
   tVNFund gives the trip delay of the fundamental frequency residual voltage stator ground fault protection.

3.12 Stator ground fault protection (neutral point voltage)

This protection function is not activated because the 95 % fundamental frequency protection in 100% stator earth fault protection is used. This function should be activated, if 100% Stator ground fault protection, 3rd harmonic based (STEFPHIZ, 59TDH) function is not chosen. The settings are done according to steps 6 and 8 for STEFPHIZ (59TDH) function.

Section 4 Analog inputs

4.1 Introduction

Analog input channels are already configured inside the IED. However the IED has to be set properly to get correct measurement results and correct protection operations. For power measuring and all directional and differential functions the directions of the input currents must be defined properly. Measuring and protection algorithms in the IED use primary system quantities. Setting values are in primary quantities as well and it is important to set the transformation ratio of the connected current and voltage transformers properly.

The availability of CT and VT inputs, as well as setting parameters depends on the ordered IED.

A reference *PhaseAngleRef* must be defined to facilitate service values reading. This analog channels phase angle will always be fixed to zero degrees and all other angle information will be shown in relation to this analog input. During testing and commissioning of the IED the reference channel can be changed to facilitate testing and service values reading.

4.2 Setting guidelines

4.2.1 Setting of the phase reference channel

All phase angles are calculated in relation to a defined reference. An appropriate analog input channel is selected and used as phase reference. The parameter *PhaseAngleRef* defines the analog channel that is used as phase angle reference.

The initially connected phase-to-earth voltage is usually chosen as *PhaseAngleRef*. A phase-to-phase voltage can also be used in theory, but a 30 degree phase shift between the current and voltage is observed in this case.

If no suitable voltage is available, the initially connected current channel can be used. Although the phase angle difference between the different phases will be firm, the whole system will appear to rotate when observing the measurement functions.

The phase reference does not work if the current channel is not available. For example, when the circuit breaker is opened and no current flows. Although the phase angle difference between the different phases is firm, the whole system appears to be rotating when the measurement functions are observed.

4.2.2 Setting of current channels

The direction of a current depends on the connection of the CT. Unless indicated otherwise, the main CTs are supposed to be Wye (star) connected. The IED can be connected with its grounding point towards the object or away from the object. This information must be set in the IED via the parameter *CT_WyePoint*, which can be changed between *FromObject* and *ToObject*. Internally in the IED algorithms and IED functions, the convention of the directionality is defined as follows:

A positive value of current, power, and so on (forward) means that the quantity has a direction towards the object. - A negative value of current, power, and so on (reverse) means a direction away from the object. See figure 23.

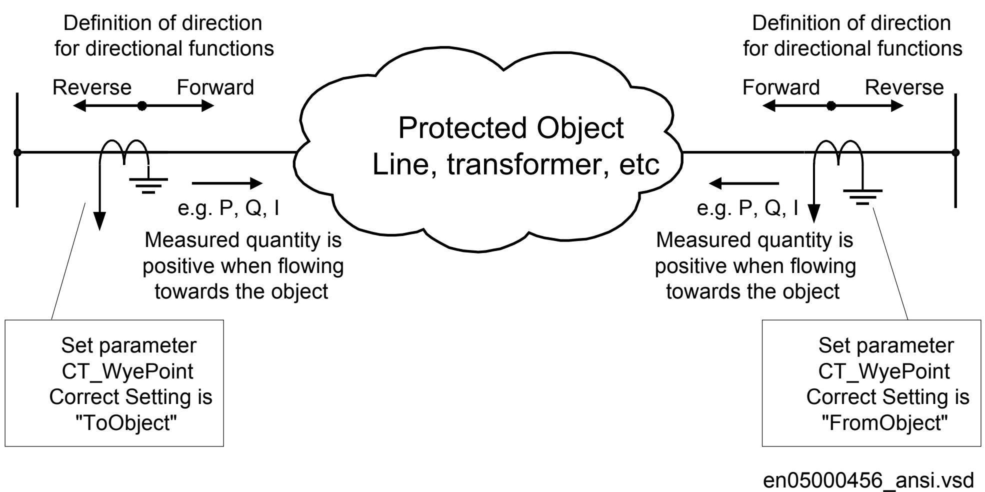


Figure 23: Internal convention of the directionality in the IED

With correct setting of the primary CT direction, *CT_WyePoint* set to *FromObject* or *ToObject*, a positive quantity always flows towards the protected object and a direction defined as Forward is always looking towards the protected object. The following examples show the principle.

4.2.2.1 Example 1

Two IEDs used for protection of two objects.

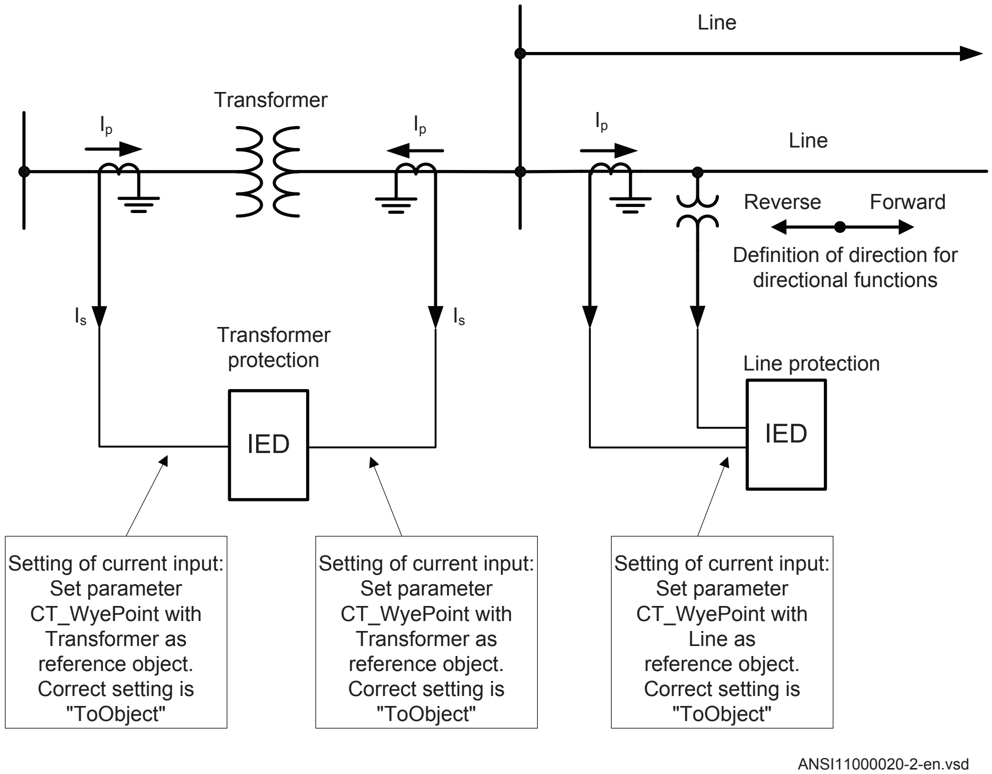
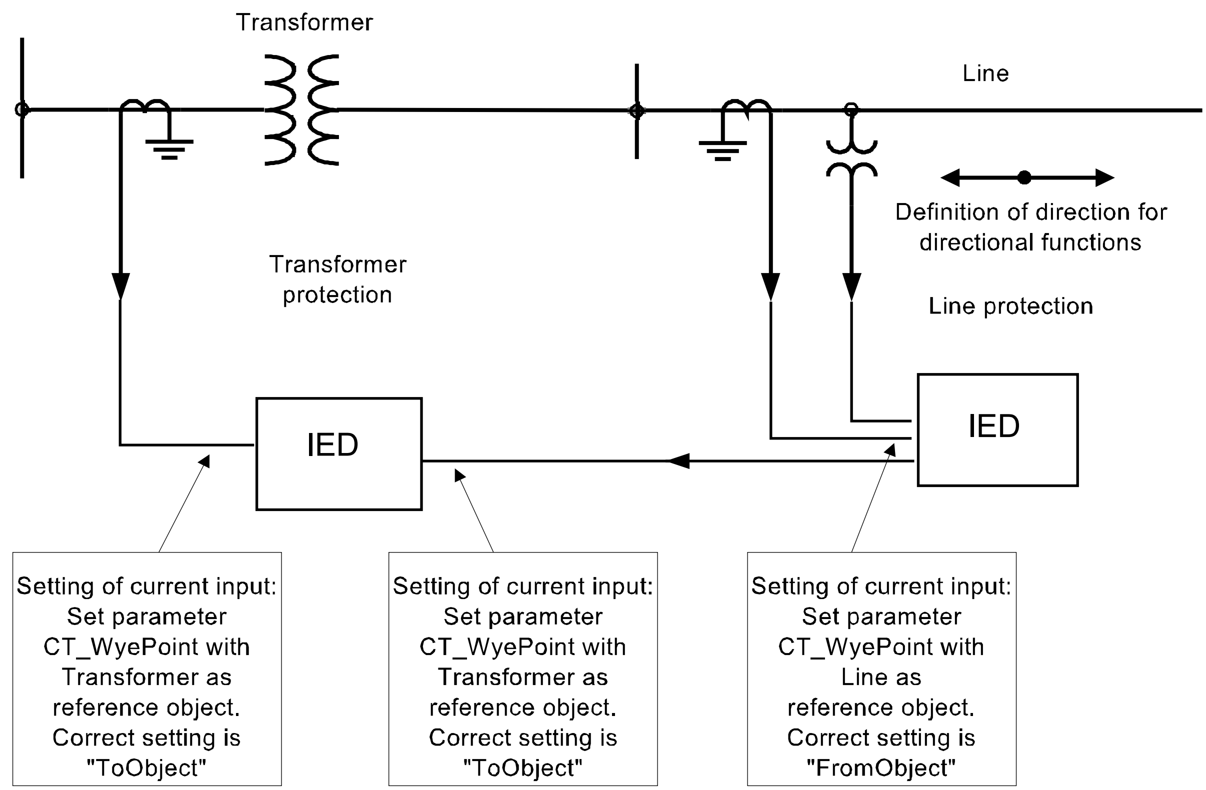


Figure 24: Example how to set CT_WyePoint parameters in the IED

The figure 24 shows the most common case where the objects have their own CTs. For the transformer protection, the protected object is the transformer. Therefore both *CT_WyePoint* directions should be set *ToObject*. For the line protection, the protected object is the line. The line CT is grounded towards the busbar, therefore the *CT_WyePoint* should be set *FromObject*.

4.2.2.2 Example 2

Two IEDs used for protection of two objects and sharing a CT.



en05000460_ansi.vsd

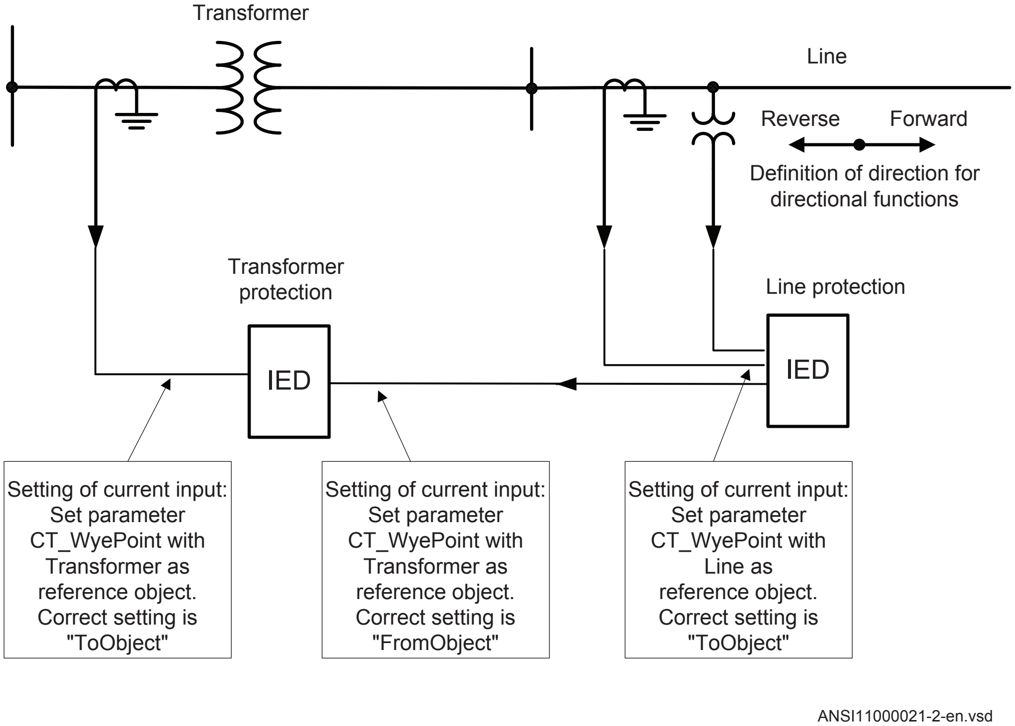


Figure 25: Example how to set CT_WyePoint parameters in the IED

This example is similar to example 1, but the power transformer is feeding just one line; both line protection IED and transformer protection IED use the same CT. The CT direction is set with different reference objects for the two IEDs though it is the same current from the same CT that is feeding the two IEDs. With these settings the directional functions of the line protection shall be set to *Forward* to look towards the line.

4.2.2.3 Examples on how to connect, configure and set CT inputs for most commonly used CT connections

Figure 26 defines the marking of current transformer terminals commonly used around the world:

In the SMAI function block, you have to set if the SMAI block is measuring current or voltage. This is done with the parameter: *AnalogInputType*: Current/voltage. The *ConnectionType*: phase -phase/ phase-earth and *GlobalBaseSel*.

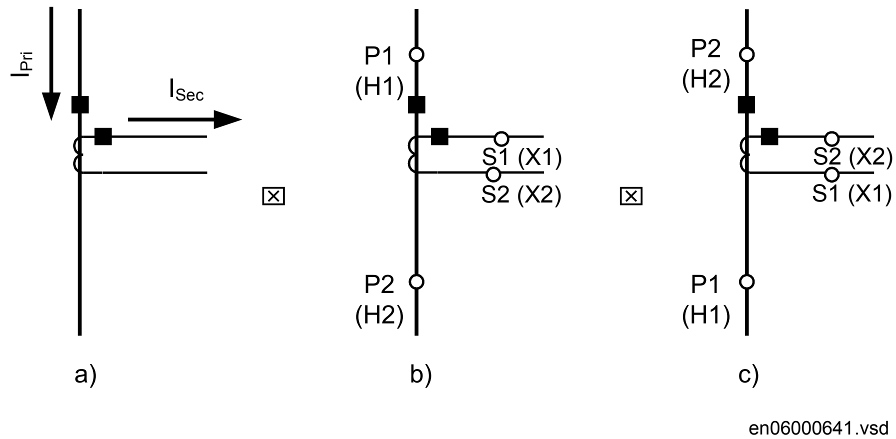


Figure 26: Commonly used markings of CT terminals

Where:

a)	is symbol and terminal marking used in this document. Terminals marked with a dot indicates the primary and secondary winding terminals with the same (that is, positive) polarity
b) and c)	are equivalent symbols and terminal marking used by IEC (ANSI) standard for CTs. Note that for these two cases the CT polarity marking is correct!

It shall be noted that depending on national standard and utility practices, the rated secondary current of a CT has typically one of the following values:

- 1A
- 5A

However in some cases the following rated secondary currents are used as well:

- 2A
- 10A

The IED fully supports all of these rated secondary values.

4.2.2.4 Example on how to connect a wye connected three-phase CT set to the IED

Figure 27 gives an example about the wiring of a wye connected three-phase CT set to the IED. It gives also an overview of the actions which are needed to make this measurement available to the built-in protection and control functions within the IED as well.

For correct terminal designations, see the connection diagrams valid for the delivered IED.

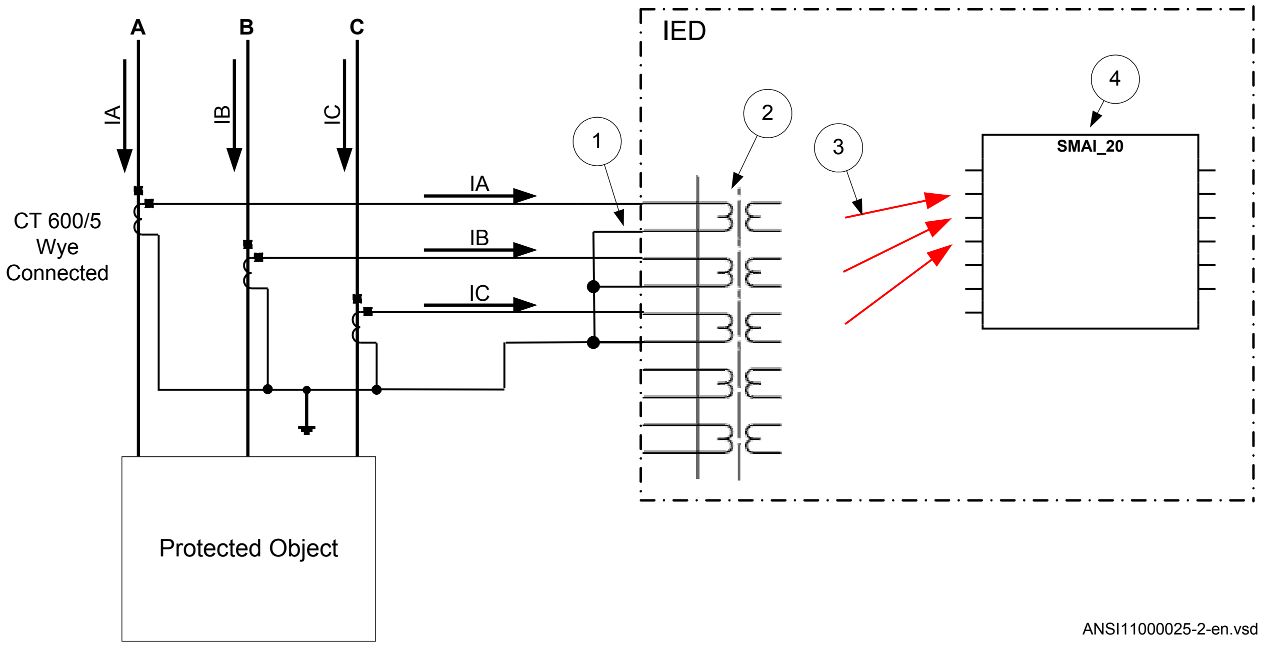


Figure 27: Wye connected three-phase CT set with wye point towards the protected object

Where:

1) The drawing shows how to connect three individual phase currents from a wye connected three-phase CT set to the three CT inputs of the IED.

2) is the TRM or AIM where these current inputs are located. It shall be noted that for all these current inputs the following setting values shall be entered.

- CTprim=600A
- CTsec=5A
- CTStarPoint=ToObject

Inside the IED only the ratio of the first two parameters is used. The third parameter as set in this example will have no influence on the measured currents (that is, currents are already measured towards the protected object).

3) are three connections, which connects these three current inputs to three input channels of the preprocessing function block 4). Depending on the type of functions, which need this current information, more than one preprocessing block might be connected in parallel to the same three physical CT inputs.

4) is a Preprocessing block that has the task to digitally filter the connected analog inputs and calculate:

- fundamental frequency phasors for all four input channels
- harmonic content for all four input channels
- positive, negative and zero sequence quantities by using the fundamental frequency phasors for the first three input channels (channel one taken as reference for sequence quantities)

These calculated values are then available for all built-in protection and control functions within the IED, which are connected to this preprocessing function block. For this application most of the preprocessing settings can be left to the default values.
If frequency tracking and compensation is required (this feature is typically required only for IEDs installed in the generating stations), then the setting parameters DFTReference shall be set accordingly.

Another alternative is to have the star point of the three-phase CT set as shown in figure 28:

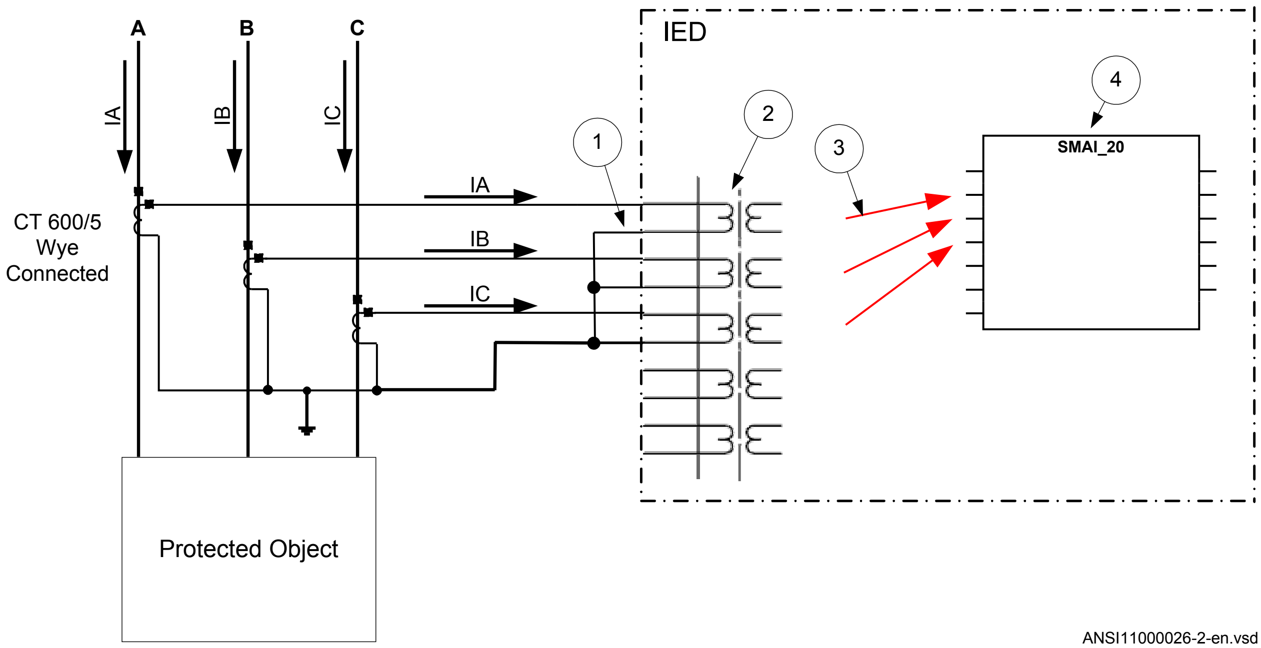


Figure 28: Wye connected three-phase CT set with its star point away from the protected object

In this case everything is done in a similar way as in the above described example, except that for all used current inputs on the TRM the following setting parameters shall be entered as shown in the example figure 28:

- *CTprim*=600A
- *CTsec*=5A
- *CTWyePoint*=FromObject

Inside the IED only the ratio of the first two parameters is used. The third parameter as set in this example will negate the measured currents in order to ensure that the currents are measured towards the protected object within the IED.

4.2.2.5 Example how to connect single-phase CT to the IED

Figure 29 gives an example how to connect the single-phase CT to the IED. It gives an overview of the required actions by the user in order to make this measurement available to the built-in protection and control functions within the IED as well.

For correct terminal designations, see the connection diagrams valid for the delivered IED.

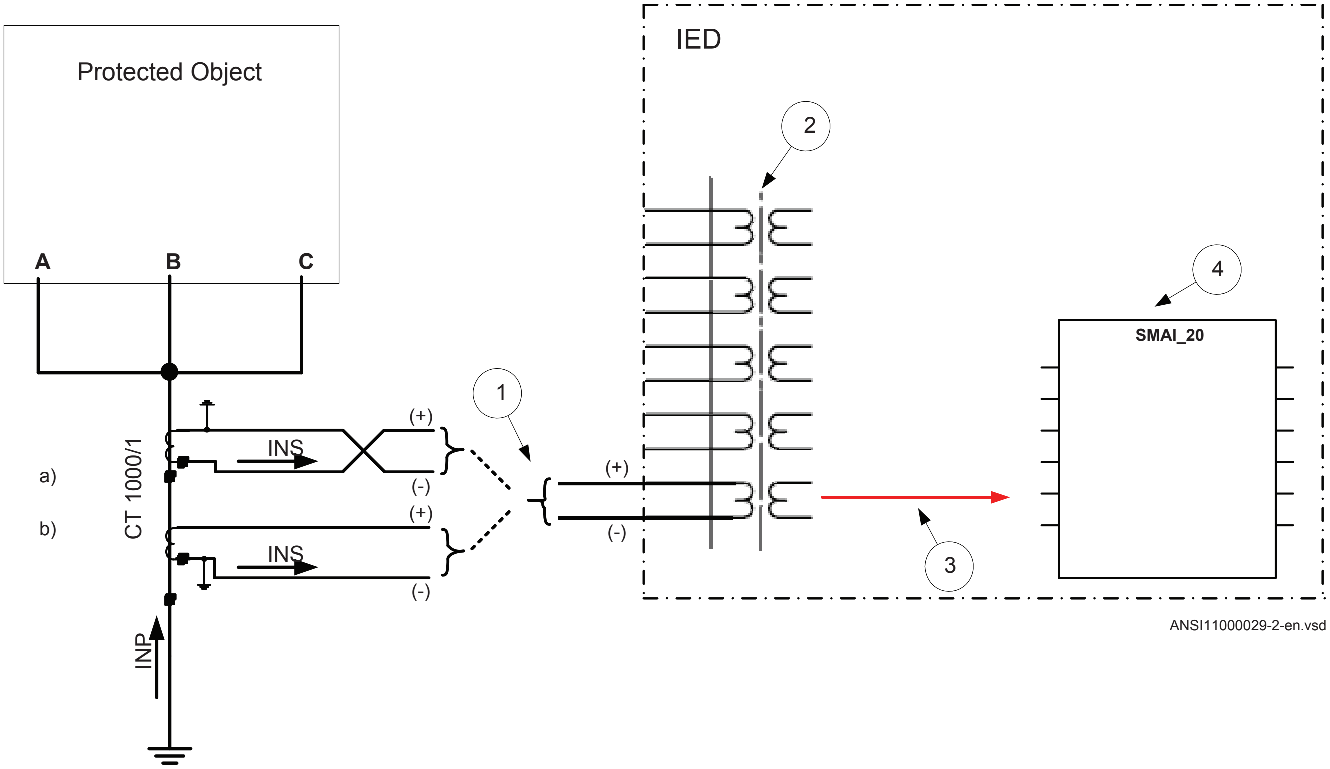


Figure 29: Connections for single-phase CT input

Where:

1) shows how to connect single-phase CT input in the IED.

2) is TRM or AIM where these current inputs are located. For all these current inputs the following setting values shall be entered.
For connection (a) shown in figure 29:

$$CTprim = 600A$$
$$CT\sec = 5A$$

(Equation 3)

CTWyePoint=*ToObject*

For connection (b) shown in figure 29:

$$CTprim = 600A$$
$$CT\sec = 5A$$

(Equation 4)

CTWyePoint=*FromObject*

3) shows the connection made in SMT tool, which connect this CT input to the fourth input channel of the preprocessing function block 4).

4) is a Preprocessing block that has the task to digitally filter the connected analog inputs and calculate:
These calculated values are then available for all built-in protection and control functions within the IED, which are connected to this preprocessing function block..
If frequency tracking and compensation is required (this feature is typically required only for IEDs installed in the generating stations) then the setting parameters *DFTReference* shall be set accordingly.

4.2.3 Setting of voltage channels

As the IED uses primary system quantities the main VT ratios must be known to the IED. This is done by setting the two parameters *VTsec* and *VTprim* for each voltage channel. The phase-to-phase value can be used even if each channel is connected to a phase-to-ground voltage from the VT.

4.2.3.1 Example

Consider a VT with the following data:

$$\frac{132\text{kV}}{\sqrt{3}} \bigg/ \frac{120\text{V}}{\sqrt{3}}$$

(Equation 5)

The following setting should be used: *VTprim=132* (value in kV) *VTsec=120* (value in V)

4.2.3.2 Examples how to connect, configure and set VT inputs for most commonly used VT connections

Figure 30 defines the marking of voltage transformer terminals commonly used around the world.

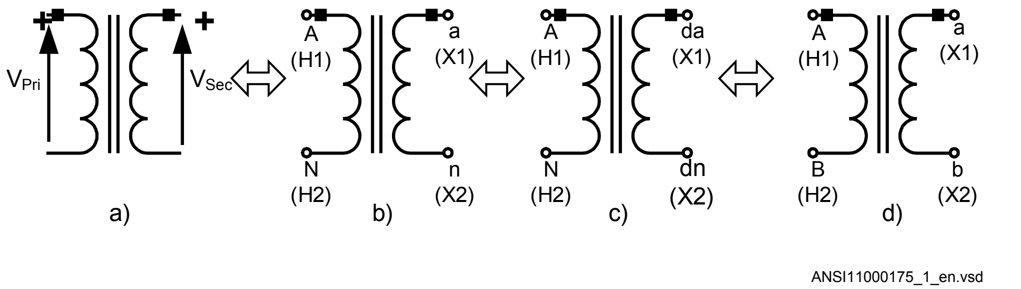


Figure 30: Commonly used markings of VT terminals

Where:

a)	is the symbol and terminal marking used in this document. Terminals marked with a dot indicate the primary and secondary winding terminals with the same (positive) polarity
b)	is the equivalent symbol and terminal marking used by IEC (ANSI) standard for phase-to-ground connected VTs
c)	is the equivalent symbol and terminal marking used by IEC (ANSI) standard for open delta connected VTs
d)	is the equivalent symbol and terminal marking used by IEC (ANSI) standard for phase-to-phase connected VTs

It shall be noted that depending on national standard and utility practices the rated secondary voltage of a VT has typically one of the following values:

- 100 V
- 110 V
- 115 V
- 120 V
- 230 V

The IED fully supports all of these values and most of them will be shown in the following examples.

4.2.3.3 Examples on how to connect a three phase-to-ground connected VT to the IED

Figure 31 gives an example about the wiring of a the three phase-to-ground connected VT to the IED. It gives aslo an overview of required actions which are needed to make this measurement available to the built-in protection and control functions within the IED.

For correct terminal designations, see the connection diagrams valid for the delivered IED.

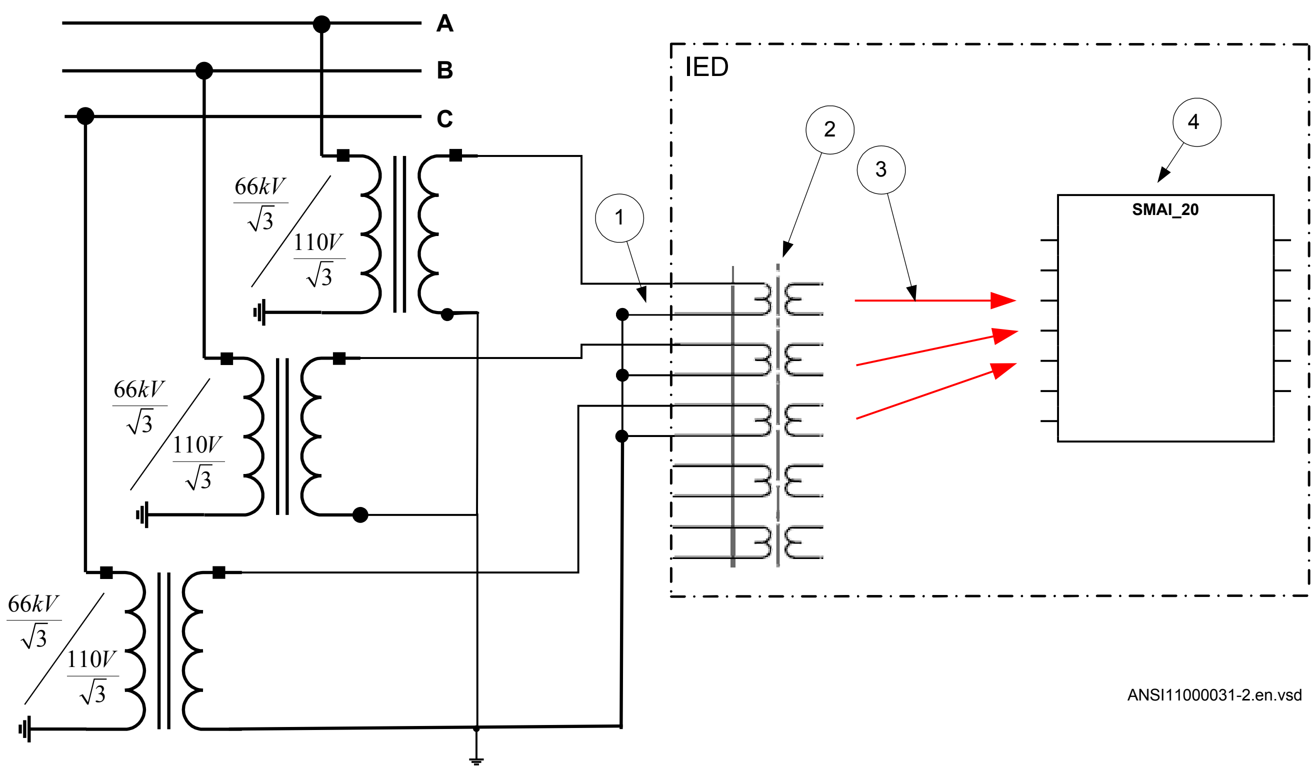


Figure 31: A Three phase-to-ground connected VT

Where:

1)

2) is the TRM or AIM where these three voltage inputs are located. For these three voltage inputs, the following setting values shall be entered:
VTprim =*66 kV*
VTsec = *110 V*
The ratio of the entered values exactly corresponds to the ratio of one individual VT.

$$\frac{66}{110} = \frac{66/\sqrt{3}}{110/\sqrt{3}}$$

(Equation 6)

3) are three connections made in Signal Matrix Tool (SMT), which connect these three voltage inputs to first three input channels of the preprocessing function block 4). Depending on the type of functions which need this voltage information, more then one preprocessing block might be connected in parallel to these three VT inputs.

4) is a Preprocessing block that has the task to digitally filter the connected analog inputs and calculate:

- fundamental frequency phasors for all four input channels
- harmonic content for all four input channels
- positive, negative and zero sequence quantities by using the fundamental frequency phasors for the first three input channels (channel one taken as reference for sequence quantities)

These calculated values are then available for all built-in protection and control functions within the IED, which are connected to this preprocessing function block in the configuration tool. For this application most of the preprocessing settings can be left to the default values.

4.2.3.4 Example how to connect the open delta VT to the IED for low impedance grounded or solidly grounded power systems

Figure 32 gives an example how to connect the open delta VT to the IED for low impedance grounded or solidly grounded power systems. It shall be noted that this type of VT connection presents secondary voltage proportional to $3V_0$ to the IED.

In case of a solid ground fault close to the VT location the primary value of 3Vo will be equal to:

$$3Vo = \frac{V_{Ph-Ph}}{\sqrt{3}} = V_{Ph-Gnd}$$

(Equation 7)

The primary rated voltage of such VT is always equal to VPh-Gnd. Therefore, three series connected VT secondary windings will give the secondary voltage equal only to

one individual VT secondary winding rating. Thus the secondary windings of such open delta VTs quite often has a secondary rated voltage close to rated phase-to-phase VT secondary voltage, that is, 115V or 115/√3V as in this particular example. Figure 32 as well gives overview of required actions by the user in order to make this measurement available to the built-in protection and control functions within the IED.

For correct connections, see the connection diagrams valid for the delivered IED.

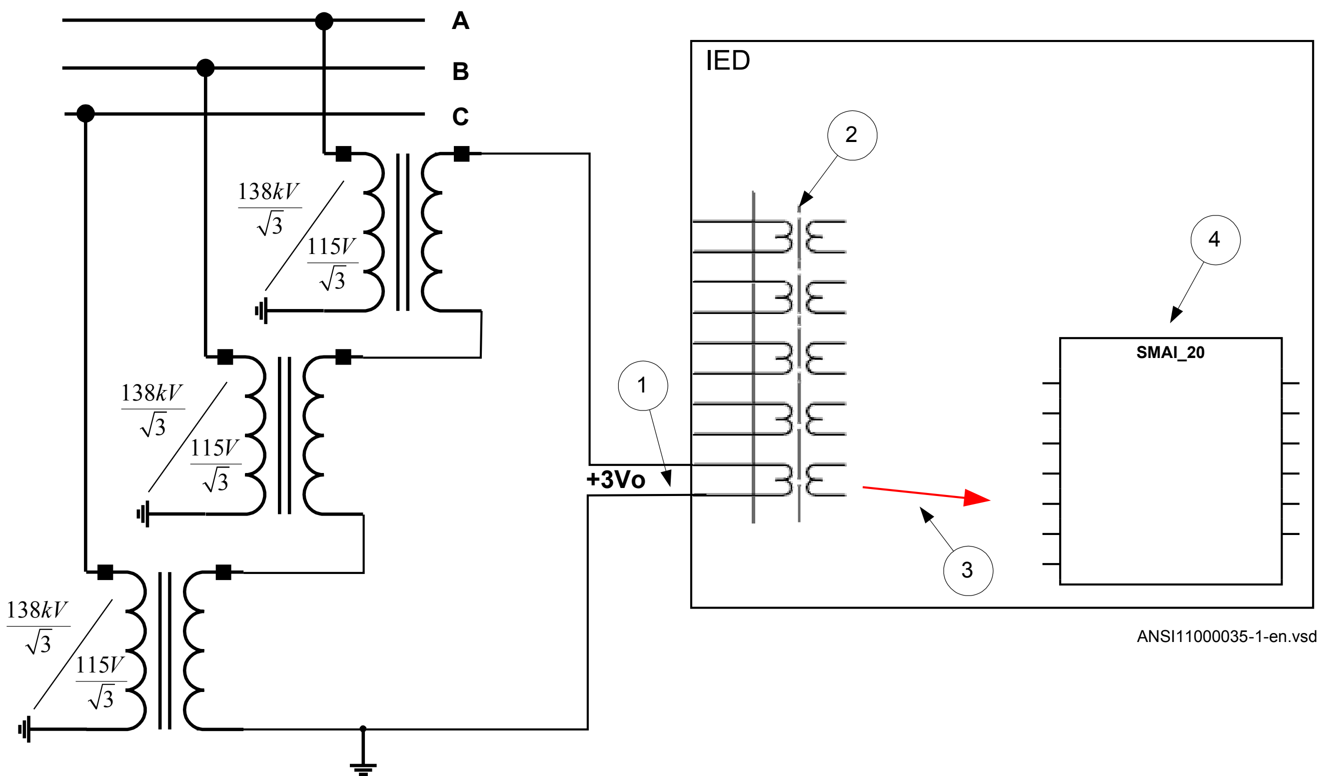


Figure 32: Open delta connected VT in low impedance or solidly grounded power system

Where:

1) shows how to connect the secondary side of open delta VT to one VT input in the IED.

+3Vo shall be connected to the IED.

2) is TRM or AIM where this voltage input is located. It shall be noted that for this voltage input the following setting values shall be entered:

$$VTprim = \sqrt{3} \cdot \frac{138}{\sqrt{3}} = 138kV$$

(Equation 8)

$$VT\sec = \sqrt{3} \cdot \frac{115}{\sqrt{3}} = 115V$$

(Equation 9)

Inside the IED, only the ratio of these two parameters is used. It shall be noted that the ratio of the entered values exactly corresponds to ratio of one individual open delta VT.

$$\frac{138}{115} = \frac{138/\sqrt{3}}{115/\sqrt{3}}$$

(Equation 10)

3) shows the connection, which connect this voltage input to the input channel of the preprocessing function block 4).

4) preprocessing block has a task to digitally filter the connected analog inputs and calculate:

- fundamental frequency phasors for all four input channels
- harmonic content for all four input channels
- positive, negative and zero sequence quantities by using the fundamental frequency phasors for the first three input channels (channel one taken as reference for sequence quantities)

These calculated values are then available for all built-in protection and control functions within the IED, which are connected to this preprocessing function block. For this application most of the preprocessing settings can be left to the default values. If frequency tracking and compensation is required (this feature is typically required only for IEDs installed in the generating stations) then the setting parameters *DFTReference* shall be set accordingly.

4.2.3.5 Example on how to connect a neutral point VT to the IED

Figure 33 gives an example on how to connect a neutral point VT to the IED. This type of VT connection presents secondary voltage proportional to V_0 to the IED.

In case of a solid ground fault in high impedance grounded or ungrounded systems the primary value of V_0 voltage will be equal to:

$$V0 = \frac{V_{ph-ph}}{\sqrt{3}} = V_{ph-Gnd}$$

(Equation 11)

Figure 33 gives an overview of required actions by the user in order to make this measurement available to the built-in protection and control functions within the IED as well.

For correct terminal designations, see the connection diagrams valid for the delivered IED.

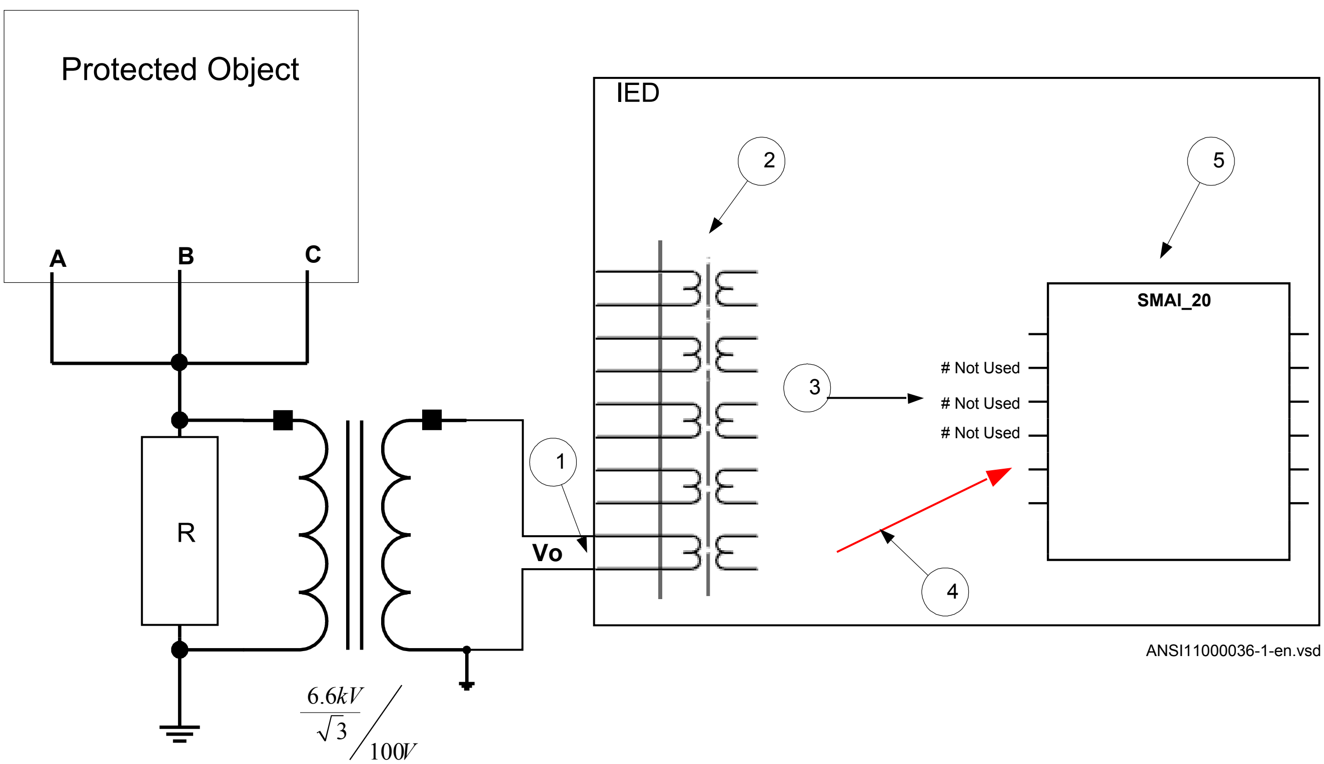


Figure 33: Neutral point connected VT

Where:

1) shows how to connect the secondary side of neutral point VT to one VT input in the IED.

V_0 shall be connected to the IED.

2) is the TRM or AIM where this voltage input is located. For this voltage input the following setting values shall be entered:

$$VTprim = \frac{6.6}{\sqrt{3}} = 3.81kV$$

(Equation 12)

$$VT\sec = 100V$$

(Equation 13)

3) shows the connection which connects this voltage input to the fourth input channel of the preprocessing function block 4).

4) is a preprocessing block that has the task to digitally filter the connected analog inputs and calculate:
These calculated values are then available for all built-in protection and control functions within the IED, which are connected to this preprocessing function block. For this application most of the preprocessing settings can be left to the default values.
If frequency tracking and compensation is required (this feature is typically required only for IEDs installed in the generating stations) then the setting parameters *DFTReference* shall be set accordingly.

Section 5 Local human-machine interface

5.1 Local HMI

Figure 34: Local human-machine interface

The LHMI of the IED contains the following elements:

- Display (LCD)
- Buttons
- LED indicators
- Communication port

The LHMI is used for setting, monitoring and controlling.

5.1.1 Display

The LHMI includes a graphical monochrome display with a resolution of 320 x 240 pixels. The character size can vary.

The display view is divided into four basic areas.

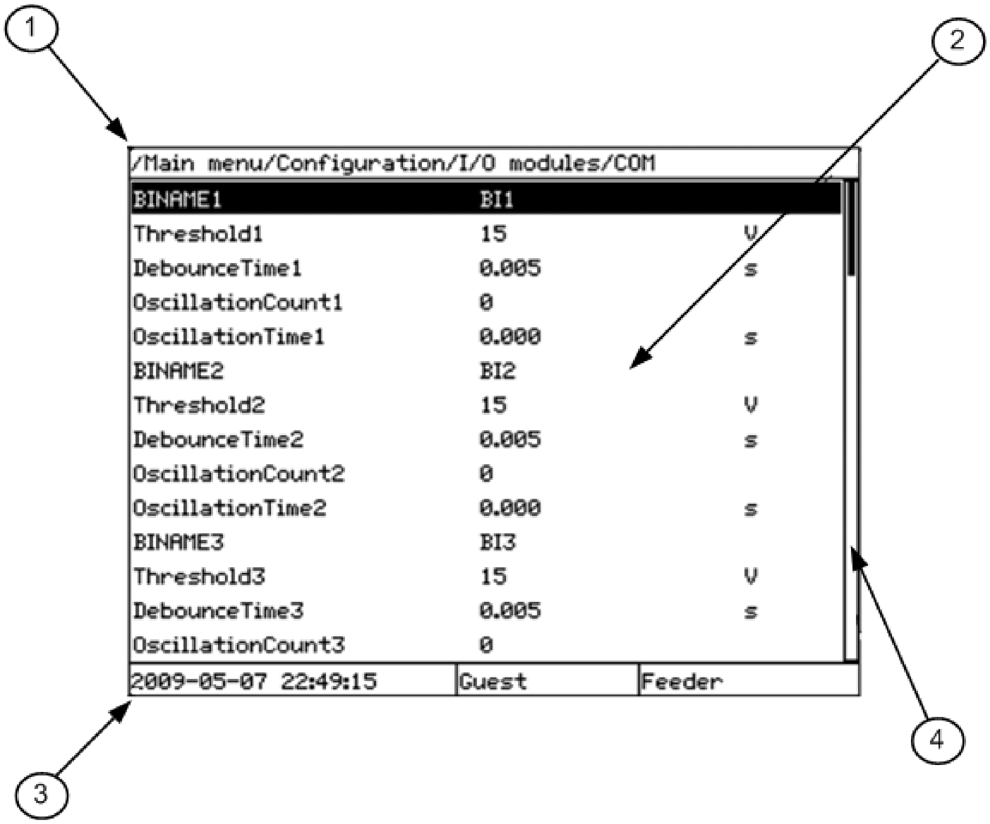


Figure 35: Display layout

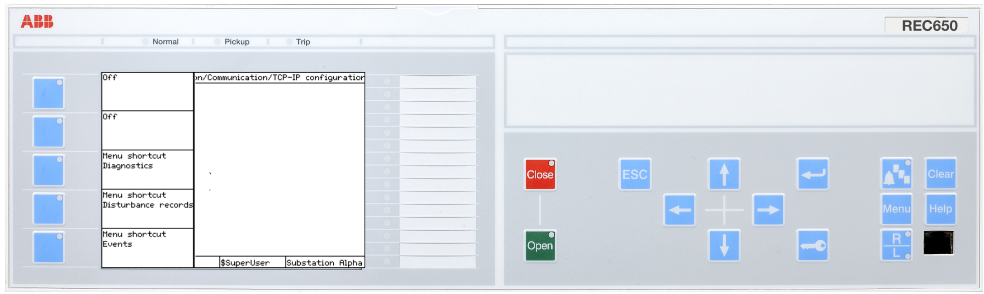
1 Path

2 Content

3 Status

4 Scroll bar (appears when needed)

The function button panel shows on request what actions are possible with the function buttons. Each function button has a LED indication that can be used as a feedback signal for the function button control action. The LED is connected to the required signal with PCM600.



ANSI12000025-1-en.vsd

Figure 36: Function button panel

The alarm LED panel shows on request the alarm text labels for the alarm LEDs.

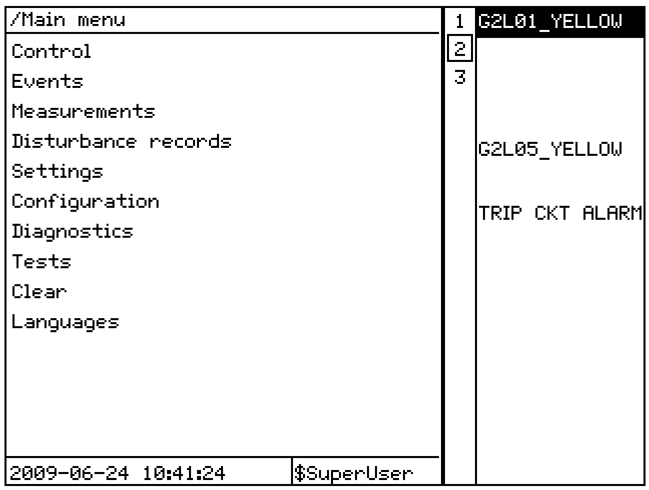


Figure 37: Alarm LED panel

The function button and alarm LED panels are not visible at the same time. Each panel is shown by pressing one of the function buttons or the Multipage button. Pressing the ESC button clears the panel from the display. Both the panels have dynamic width that depends on the label string length that the panel contains.

5.1.2 LEDs

The LHMI includes three protection status LEDs above the display: Normal, Pickup and Trip.

There are 15 programmable alarm LEDs on the front of the LHMI. Each LED can indicate three states with the colors: green, yellow and red. The alarm texts related to each three-color LED are divided into three pages.

There are 3 separate pages of LEDs available. The 15 physical three-color LEDs in one LED group can indicate 45 different signals. Altogether, 135 signals can be indicated since there are three LED groups. The LEDs can be configured with PCM600 and the operation mode can be selected with the LHMI or PCM600.

There are two additional LEDs which are embedded into the control buttons  and . They represent the status of the circuit breaker.

5.1.3 Keypad

The LHMI keypad contains push-buttons which are used to navigate in different views or menus. The push-buttons are also used to acknowledge alarms, reset indications, provide help and switch between local and remote control mode.

The keypad also contains programmable push-buttons that can be configured either as menu shortcut or control buttons.

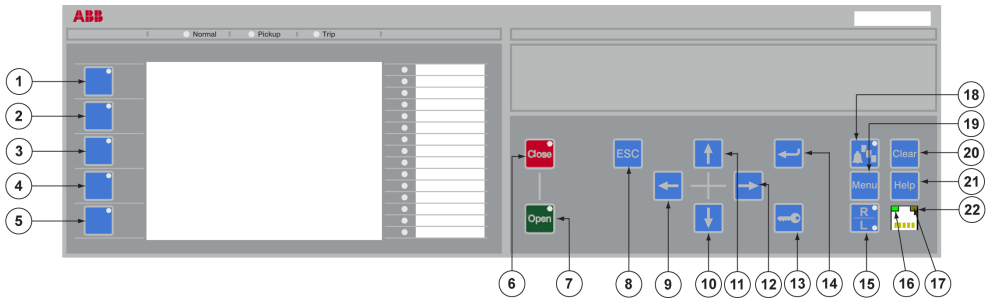


Figure 38: LHMI keypad with object control, navigation and command push buttons and RJ-45 communication port

1...5	Function button
6	Close
7	Open
8	Escape
9	Left
10	Down
11	Up
12	Right
13	Key
14	Enter
15	Remote/Local
16	Uplink LED
17	Not in use
18	Multipage
19	Menu
20	Clear
21	Help
22	Communication port

5.1.4 Local HMI functionality

5.1.4.1 Protection and alarm indication

Protection indicators

The protection indicator LEDs are Normal, Pickup and Trip.

Table 14: Normal LED (green)

LED state	Description
Off	Auxiliary supply voltage is disconnected.
On	Normal operation.
Flashing	Internal fault has occurred.

Table 15: PickUp LED (yellow)

LED state	Description
Off	Normal operation.
On	A protection function has picked up and an indication message is displayed. • If several protection functions Pickup within a short time, the last Pickup is indicated on the display.
Flashing	A flashing yellow LED has a higher priority than a steady yellow LED. The IED is in test mode and protection functions are blocked. • The indication disappears when the IED is no longer in test mode and blocking is removed.

Table 16: Trip LED (red)

LED state	Description
Off	Normal operation.
On	A protection function has tripped and an indication message is displayed. • The trip indication is latching and must be reset via communication or by pressing Clear.

Alarm indicators

The 15 programmable three-color LEDs are used for alarm indication. An individual alarm/status signal, connected to any of the LED function blocks, can be assigned to one of the three LED colors when configuring the IED.

Table 17: Alarm indications

LED state	Description
Off	Normal operation. All activation signals are off.
On	• Follow-S sequence: The activation signal is on. • LatchedColl-S sequence: The activation signal is on, or it is off but the indication has not been acknowledged. • LatchedAck-F-S sequence: The indication has been acknowledged, but the activation signal is still on. • LatchedAck-S-F sequence: The activation signal is on, or it is off but the indication has not been acknowledged. • LatchedReset-S sequence: The activation signal is on, or it is off but the indication has not been acknowledged.
Flashing	• Follow-F sequence: The activation signal is on. • LatchedAck-F-S sequence: The activation signal is on, or it is off but the indication has not been acknowledged. • LatchedAck-S-F sequence: The indication has been acknowledged, but the activation signal is still on.

5.1.4.2 Parameter management

The LHMI is used to access the IED parameters. Three types of parameters can be read and written.

- Numerical values
- String values
- Enumerated values

Numerical values are presented either in integer or in decimal format with minimum and maximum values. Character strings can be edited character by character. Enumerated values have a predefined set of selectable values.

5.1.4.3 Front communication

The RJ-45 port in the LHMI enables front communication.

- The green uplink LED on the left is lit when the cable is successfully connected to the port.

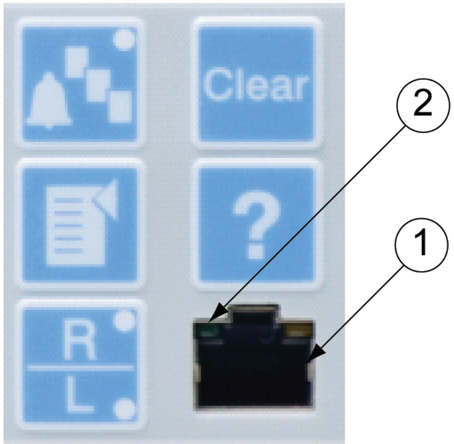


Figure 39: RJ-45 communication port and green indicator LED

1 RJ-45 connector

2 Green indicator LED

When a computer is connected to the IED front port with a crossed-over cable, the IED's DHCP server for the front interface assigns an IP address to the computer if *DHCPServer* = *Enabled*. The default IP address for the front port is 10.1.150.3.

Do not connect the IED front port to a LAN. Connect only a single local PC with PCM600 to the front port.

5.1.4.4 Single-line diagram

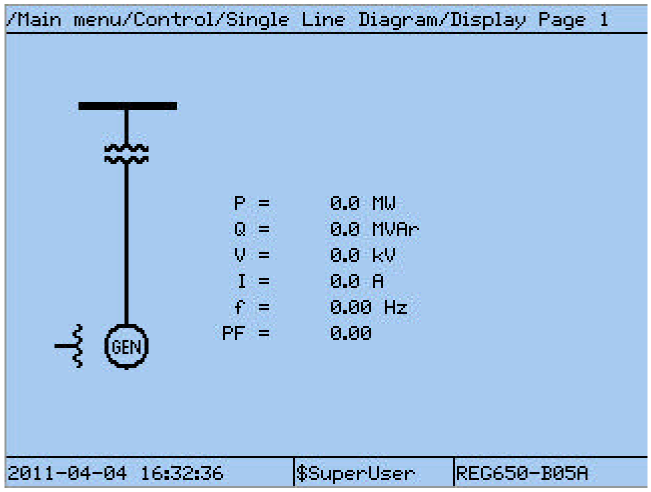


Figure 40: Single-line diagram example (REG650)

Section 6 Differential protection

6.1 Transformer differential protection T2WPDIF (87T) and T3WPDIF (87T)

6.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Transformer differential protection, two-winding	T2WPDIF	3Id/I	87T
Transformer differential protection, three-winding	T3WPDIF	3Id/I	87T

6.1.2 Application

The transformer differential protection is a unit protection. It serves as the main protection of transformers in case of winding failure. The protective zone of a differential protection includes everything between the connected CTs. This includes the transformer and may include the bus-works or cables.

A transformer differential protection compares the current flowing into the transformer with the current leaving the transformer. A correct analysis of fault conditions by the differential protection must take into consideration changes due to the voltage, current and phase angle transformation caused by the protected transformer. Traditional transformer differential protection functions required auxiliary transformers for correction of the phase shift and transformation ratio. The numerical microprocessor based differential algorithm as implemented in the IED compensates for both the turns-ratio and the phase shift internally in the software. No auxiliary current transformers are necessary.

The differential current should theoretically be zero during normal load or during external faults if the turn-ratio and the phase shift are correctly compensated for. However, there are several different phenomena other than internal faults that will cause result in unwanted and false differential currents. The main reasons for unwanted differential currents are:

- mismatch due to varying tap changer positions
- different characteristics, loads and operating conditions of the current transformers
- zero sequence currents that only flow on one side of the power transformer
- normal magnetizing currents
- magnetizing inrush currents
- overexcitation magnetizing currents

6.1.3 Setting guidelines

The parameters for the Transformer differential protection function are set via the local HMI or Protection and Control IED Manager (PCM600).

IED values for the primary current (setting *IBase*), the primary voltage (setting *VBase*) and the primary power (setting *SBase*) for a particular winding are set as a global base value GBASVAL. The settings *GlobalBaseSelW1*, *GlobalBaseSelW2* and *GlobalBaseSelW3* in the differential protection function are used to select the corresponding GBASVAL function as a reference.

6.1.3.1 Inrush restraint methods

With a combination of the second harmonic restraint and the waveform restraint methods it is possibly to create a protection with high security and stability against transformer inrush effects and at the same time maintain stability in case of heavy external faults, even if the current transformers are saturated. The second harmonic restraint function has a settable level. If the ratio of the second harmonic to fundamental harmonic content in the differential current is above the settable limit, the operation of the differential protection is restrained. It is recommended to keep the parameter *I2/I1Ratio = 15%* as the default value in case no special reasons exist to choose a different value.

6.1.3.2 Overexcitation restraint method

Overexcitation current contains odd harmonics, because the waveform is symmetrical about the time axis. As the third harmonic currents cannot flow into a delta winding, the fifth harmonic is the lowest harmonic which can serve as a criterion for overexcitation. The differential protection function is provided with a fifth harmonic restraint to prevent the protection from operation during an overexcitation condition of

a power transformer. If the ratio of the fifth harmonic to fundamental harmonic in the differential current is above a settable limit the operation is restrained. It is recommended to use *I5/I1Ratio = 25%* as default value in case no special reasons exist to choose another setting. Transformers likely to be exposed to overvoltage or underfrequency conditions (that is, generator step-up transformers in power stations) should be provided with an overexcitation protection based on V/Hz to achieve a trip before the core thermal limit is reached.

6.1.3.3 Cross-blocking between phases

The basic definition of cross-blocking is that one of the three phases can block operation (that is, tripping) of the other two phases due to the harmonic pollution (2nd or 5th harmonic content) or waveform characteristic of the differential current in that phase the user can control the cross-blocking between the phases via the setting parameter *CrossBlockEn*.

When the parameter *CrossBlockEn* is set to *Enabled*, cross blocking between phases will be introduced. The phase with the operating point above the set bias characteristic will be able to cross-block the other two phases if it is self-blocked by any of the previously explained restrain criteria. As soon as the operating point for this phase is below the set bias characteristic, cross blocking from that phase will be inhibited. The default (recommended) setting value for this parameter is *Enabled*. When parameter *CrossBlockEn* is set to *Disabled*, any cross blocking between phases will be disabled.

6.1.3.4 Restrained and unrestrained differential protection

The first section of the restrain characteristic gives the highest sensitivity and is used to determine small or high impedance fault within the protected zone.

The second section of the restrain characteristic has an increased slope in order to deal with increased differential current due to additional power transformer losses during heavy loading of the transformer and external fault currents. The third section of the restrain characteristic decreases the sensitivity of the restrained differential function further in order to cope with CT saturation and transformer losses during heavy through faults. A default setting for the operating characteristic with *IdMin = 0.3 * IBase* is recommended in normal applications. If the conditions are known in more detail, higher or lower sensitivity can be chosen. The selection of suitable characteristic should in such cases be based on the knowledge of the class of the current transformers, availability of information on the tap changer position, short circuit power of the systems, and so on.

The unrestrained operation level has a default value of *IdUnre = 10pu*, which is typically acceptable for most of the standard power transformer applications. In the following case, this setting need to be changed accordingly:

- For differential applications on HV shunt reactors, due to the fact that there is no heavy through-fault condition, the unrestrained differential operation level can be set to *IdUnre = 1.75pu*for additional security

The overall operating characteristic of the transformer differential protection is shown in figure 41.

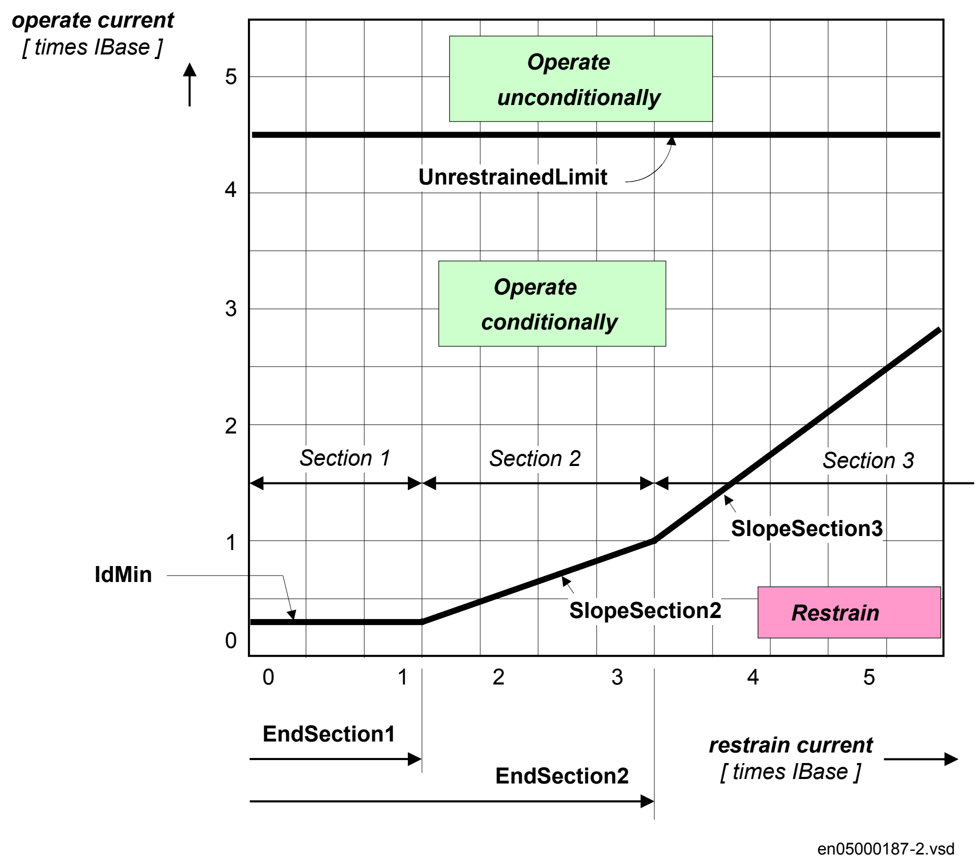


Figure 41: Representation of the restrained-, and the unrestrained operate characteristics

$$slope = \frac{\Delta Ioperate}{\Delta Irestrain} \cdot 100\%$$

(Equation 14)

and where the restrained characteristic is defined by the settings:

1. *IdMin*
2. *EndSection1*
3. *EndSection2*
4. *SlopeSection2*
5. *SlopeSection3*

6.1.3.5 Elimination of zero sequence currents

A differential protection may operate unwanted due to external ground-faults in cases where the zero sequence current can flow on only one side of the power transformer. This is the case when zero sequence current cannot be properly transformed to the other side of the power transformer. Power transformer connection groups of the Wye/ Delta or Delta/Wye type cannot transform zero sequence current. If a delta winding of a power transformer is grounded via a grounding transformer inside the zone protected by the differential protection there will be an unwanted differential current in case of an external ground-fault. The same is true for an grounded star winding. Even if both the wye and delta winding are earthed, the zero sequence current is usually limited by the grounding transformer on the delta side of the power transformer, which may result in differential current as well. To make the overall differential protection insensitive to external gound-faults in these situations the zero sequence currents must be eliminated from the power transformer IED currents on the grounded windings, so that they do not appear as differential currents. The elimination of zero sequence current is done numerically by setting *ZSCurrSubtrWx=Disabled* or *Enabled* and doesn't require no auxiliary transformers or zero sequence traps.

6.1.3.6 Internal/External fault discriminator

The internal/external fault discriminator operation is based on the relative position of the two phasors (in case of a two-winding transformer) representing the W1 and W2 negative sequence current contributions. It performs a directional comparison between these two phasors.

In order to perform a directional comparison of the two phasors their magnitudes must be high enough so that one can be sure that they are due to a fault. On the other hand, in order to guarantee a good sensitivity of the internal/external fault discriminator, the value of this minimum limit must not be too high. Therefore this limit value (*IMinNegSeq*) is settable in the range from 1% to 20% of the respective winding current. The default value is 4%. Only if the magnitude of both negative sequence current contributions are above the set limit, the relative position between these two phasors is checked. If either of the negative sequence current contributions is too small (less than the set value for *IMinNegSeq*), no directional comparison is made in order to avoid the possibility to produce a wrong decision.

This magnitude check, guarantees stability of the algorithm when the power transformer is energized, since no current will be measured on the low voltage side of the power transformer. In cases where the protected transformer can be energized with a load connected on the LV side (e.g. a step-up transformer in a power station with directly connected auxiliary transformer on its LV side) the value for this setting shall be increased to at least 12%. This is necessary in order to prevent unwanted operation due to LV side currents during the transformer energization.

The setting *NegSeqROA* represents the so-called Relay Operate Angle, which determines the boundary between the internal and external fault regions. It can be selected in the range from 30 degrees to 90 degrees, with a step of 1 degree. The default value is 60 degrees. The default setting 60 degrees somewhat favors security in comparison to dependability. If the user has no well-justified reason for another value, 60 degrees shall be applied.

If the above conditions concerning magnitudes are fulfilled, the internal/external fault discriminator compares the relative phase angle between the negative sequence current contributions from the HV side and LV side of the power transformer using the following two rules (assuming both CT's have their grounding point connected towards the object):

- If the negative sequence currents contributions from HV and LV sides are in phase or at least in the internal fault region, the fault is internal.
- If the negative sequence currents contributions from HV and LV sides are 180 degrees out of phase or at least in the external fault region, the fault is external.

Under external fault condition and with no current transformer saturation, the relative angle is theoretically equal to 180 degrees. During internal fault and with no current transformer saturation, the angle shall ideally be 0 degrees, but due to possible different negative sequence source impedance angles on HV and LV side of power transformer, it may differ somewhat from the ideal zero value.

The internal/external fault discriminator has proved to be very reliable. If a fault is detected, and at the same time the internal/external fault discriminator characterizes this fault as an internal, any eventual blocking signals produced by either the harmonic or the waveform restraints are ignored.

If the bias current is more than 110% of IBase, the negative sequence threshold (*IMinNegSeq*) is increased linearly to desensitize the internal/external fault discriminator during through faults and CT saturation, which will create false negative sequence currents. This assures response times of the differential protection below one power system cycle (below 16.66mS for 60 Hz system) for all more severe internal faults. Even for heavy internal faults with severely saturated current transformers the internal/external fault discriminator will make the differential protection operate well below one cycle, since the harmonic distortions in the differential currents do not slow down the differential protection operation.

The sensitive negative sequence current based differential protection, which detects minor internal faults, and where the speed is not as essential as stability against unwanted trips, is restrained when the bias current is more than 150% of *IBase*. For the sensitive negative sequence protection to be reactivated, the bias current must drop back below 110% of *IBase*. The sensitive negative sequence protection is always restrained by the harmonic restraint.

External faults happen ten to hundred times more often than internal ones as far as the power transformers are concerned. If a disturbance is detected and the internal/external fault discriminator characterizes this fault as an external fault, the conventional additional criteria (2nd harmonic, 5th harmonic, waveform block) are posed on the differential algorithm before its trip is allowed. This assures high stability during external faults. However, at the same time the differential function is still capable of trip ping quickly for evolving faults.

The principle of the internal/external fault discriminator can be extended to autotransformers and transformers with three windings. If all three windings are connected to their respective networks then three directional comparisons are made, but only two comparisons are necessary in order to positively determine the position of the fault with respect to the protected zone. The directional comparisons are: W1 - (W2 + W3); W2 - (W1 + W3); W3 - (W1 + W2). The rule applied by the internal/external fault discriminator in case of three-winding power transformers is:

- If all comparisons indicate an internal fault, then it is an internal fault.
- If any comparison indicates an external fault, then it is an external fault

If one of the windings is not connected, the algorithm automatically reduces to the two-winding version. Nevertheless, the whole power transformer is protected, including the non-connected winding.

6.1.3.7 Differential current alarm

Differential protection continuously monitors the level of the fundamental frequency differential currents and gives an alarm if the pre-set value is simultaneously exceeded in all three phases. Set the time delayed defined by parameter *tAlarmDelay* two times longer than the on-load tap-changer mechanical operating time (For example, typical setting value 10s).

6.1.3.8 Switch onto fault feature

The Transformer differential (TW2PDIF for two winding and TW3PDIF for three winding) (87T) function in the IED has a built-in, advanced switch onto fault feature. This feature can be enabled or disabled by the setting parameter *SOTFMode*. When *SOTFMode* = *Enabled* this feature is enabled. It shall be noted that when this feature is enabled it is not possible to test the 2nd harmonic blocking feature by simply injecting one current with superimposed second harmonic. In that case the switch on to fault feature will operate and the differential protection will trip. However for a real inrush case the differential protection function will properly restrain from operation.

For more information about the operating principles of the switch onto fault feature please read the *“Technical Manual”*..

6.1.4 Setting example

6.1.4.1 CT Connections

The IED has been designed with the assumption that all main CTS are wye connected. The IED can be used in applications where the main CTs are delta connected. For such applications the following shall be kept in mind:

1. The ratio for delta connected CTs shall be set √(3)=1.732 times smaller than the actual individual phase CT ratio.
2. The power transformer phase-shift shall typically be set as Yy0 because the compensation for the actual phase shift is provided by the external delta CT connection.
3. The zero sequence current is eliminated by the main CT delta connections. Thus on sides where CTs are connected in delta the zero sequence current elimination shall be set to Off in the IED.

The following table summarizes the most commonly used wye-delta phase-shift around the world and provides information about the required type of main CT delta connection on the wye side of the protected transformer.

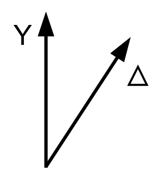
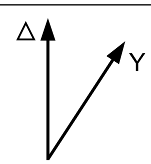
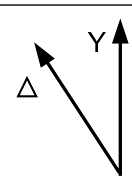
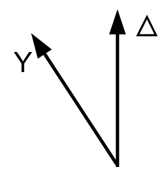
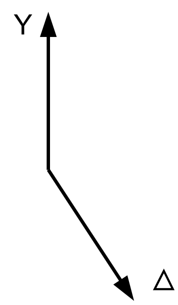
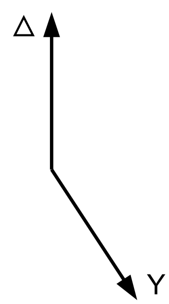
IEC vector group	ANSI designation	Positive sequence no-load voltage phasor diagram	Required delta CT connection type on wye side of the protected power transformer and internal vector group setting in the IED
YNd1	YD_{AC}		Yy0
Dyn1	$D_{AB}Y$		Yy0
YNd11	YD_{AB}		Yy0

Table continues on next page

IEC vector group	ANSI designation	Positive sequence no-load voltage phasor diagram	Required delta CT connection type on wye side of the protected power transformer and internal vector group setting in the IED
Dyn11	$D_{AC}Y$		Yy0
YNd5	YD150		Yy6
Dyn5	DY150		Yy6

6.2 1Ph High impedance differential protection HZPDIF (87)

6.2.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
1Ph High impedance differential protection	HZPDIF	*Id*	87

6.2.2 Application

The 1Ph High impedance differential protection function HZPDIF (87) can be used as a restricted earth fault protection.

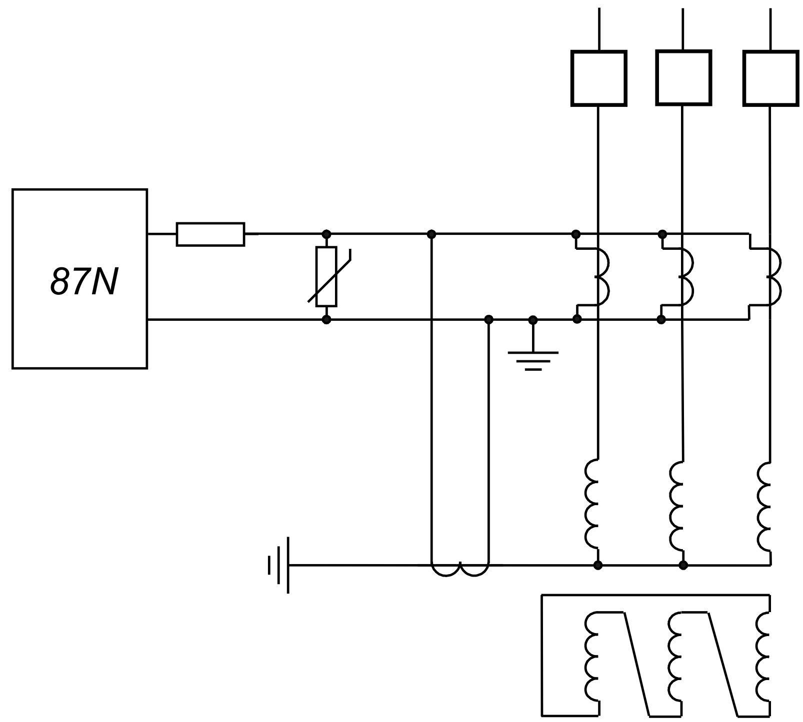


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Figure 42: Application of a 1Ph High impedance differential protection HZPDIF (87) function

6.2.2.1 The basics of the high impedance principle

The high impedance differential protection principle has been used for many years and is well documented. The operating characteristic provides very good sensitivity and high speed operation. One main benefit offered by the principle is an absolute stability (that is, non-operation) for external faults even in the presence of heavy CT saturation. The principle is based on the CT secondary current circulating between involved current transformers and not through the IED due to its high impedance, normally in the range of hundreds of ohms and sometimes above Kiloohm. When an internal fault occurs the current cannot circulate and is forced through the differential circuit causing operation.

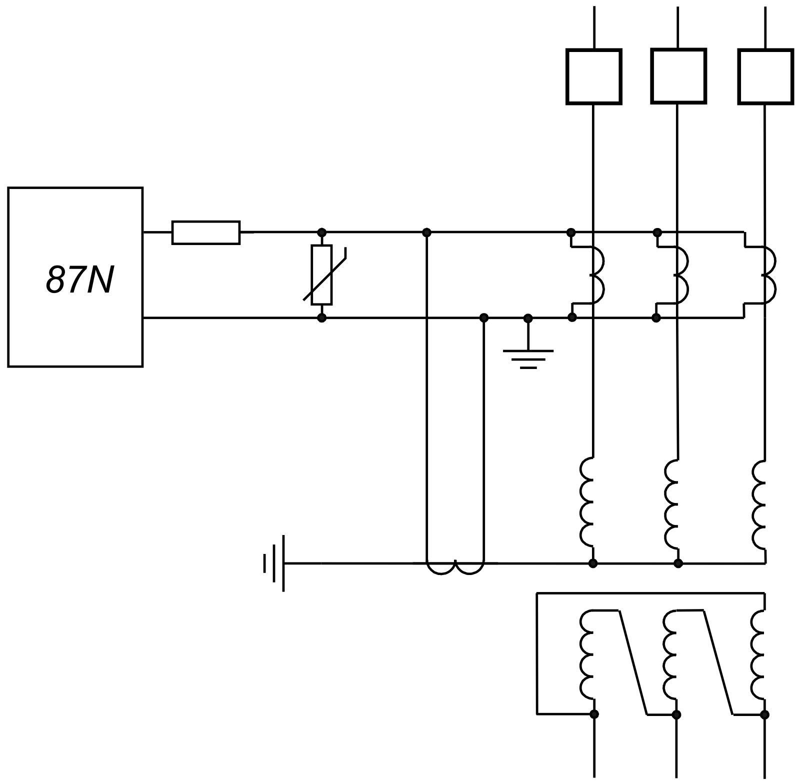

Figure 43: Example for the high impedance restricted earth fault protection application

For a through fault one current transformer might saturate when the other CTs still will feed current. For such a case a voltage will be developed across the stabilising resistor. The calculations are made with the worst situations in mind and a minimum operating voltage V_R is calculated according to equation 15

$$VR > IF\ \max \cdot \left(Rct + Rl \right)$$

(Equation 15)

where:

*IF*max	is the maximum through fault current at the secondary side of the CT
Rct	is the current transformer secondary resistance and
Rl	is the maximum loop resistance of the circuit at any CT.

The minimum operating voltage has to be calculated (all loops) and the function is set higher than the highest achieved value (setting *TripPickup*). As the loop resistance is the value to the connection point from each CT, it is advisable to do all the CT core summations in the switchgear to have shortest possible loops. This will give lower setting values and also a better balanced scheme. The connection in to the control room can then be from the most central bay.

For an internal fault, circulation is not possible, due to the high impedance. Depending on the size of current transformer, relatively high voltages will be developed across the series resistor. Note that very high peak voltages can appear. To prevent the risk of flashover in the circuit, a voltage limiter must be included. The voltage limiter is a voltage dependent resistor (Metrosil).

The external unit with stabilizing resistor has a value of either 6800 ohms or 1800 ohms (depending on ordered alternative) with a shorting link to allow adjustment to the required value. Select a suitable value of the resistor based on the VR voltage calculated. A higher resistance value will give a higher sensitivity and a lower value a lower sensitivity.

The function has a recommended operating current range 40 mA to 1.0A for 1 A inputs and 200 mA to 5A for 5A inputs. This, together with the selected and set value, is used to calculate the required value of current at the set *TripPickup* and *R series* values.

The CT inputs used for 1Ph High impedance differential protection HZPDIF (87) function, shall be set to have ratio 1:1. So the parameters CT_{secx} and CT_{primx} of the relevant channel x of TRM and/or AIM shall be set equal to 1 A by PST in PCM600; The parameter *CTStarPointx* may be set to *ToObject*.

The tables 18, 19 below show, the operating currents for different settings of operating voltages and selected resistances. Adjust as required based on tables 18, 19 or to values in between as required for the application.

Minimum ohms can be difficult to adjust due to the small value compared to the total value.

Normally the voltage can be increased to higher values than the calculated minimum *TripPickup* with a minor change of total operating values as long as this is done by adjusting the resistor to a higher value. Check the sensitivity calculation below for reference.

Table 18: 1 A channels: input with minimum operating down to 20 mA

Operating voltage *TripPickup*	Stabilizing resistor R ohms	Operating current level 1 A	Stabilizing resistor R ohms	Operating current level 1 A	Stabilizing resistor R ohms	Operating current level 1 A
20 V	1000	0.020 A	--	--	--	--
40 V	2000	0.020 A	1000	0.040 A	--	--
60 V	3000	0.020 A	1500	0.040 A	600	0.100 A
80 V	4000	0.020 A	2000	0.040 A	800	0.100 A
100 V	5000	0.020 A	2500	0.040 A	1000	0.100 A
150 V	6000	0.020 A	3750	0.040 A	1500	0.100 A
200 V	6800	0.029 A	5000	0.040 A	2000	0.100 A

Table 19: 5 A channels: input with minimum operating down to 100 mA

Operating voltage *TripPickup*	Stabilizing resistor R1 ohms	Operating current level 5 A	Stabilizing resistor R1 ohms	Operating current level 5 A	Stabilizing resistor R1 ohms	Operating current level 5 A
20 V	200	0.100 A	100	0.200 A	--	--
40 V	400	0.100 A	200	0.200 A	100	0.400
60 V	600	0.100 A	300	0.200 A	150	0.400 A
80 V	800	0.100 A	400	0.200 A	200	0.400 A
100 V	1000	0.100 A	500	0.200 A	250	0.400 A
150 V	1500	0.100 A	750	0.200 A	375	0.400 A
200 V	2000	0.100 A	1000	0.200 A	500	0.400 A

The current transformer saturating voltage must be at least 2 · *TripPickup* to have sufficient operating margin. This must be checked after calculation of *TripPickup*.

When the R value has been selected and the *TripPickup* value has been set, the sensitivity of the scheme *IP* can be calculated. The sensitivity is decided by the total current in the circuit according to equation 16.

$$IP = n \cdot (IR + Ires + \sum lmag)$$

(Equation 16)

where:	
n	is the CT ratio
IP	primary current at IED pickup,

Table continues on next page

IR	IED pickup current
Ires	is the current through the non-linear resistorand
ΣImag	is the sum of the magnetizing currents from all CTs in the circuit (for example, 4 CTs for restricted earth fault protection, 2 CTs for reactor differential protection, 3-5 CTs for autotransformer differential protection , the number of feeders, including the buscoupler, for busbar differential protection).

It should be remembered that the vectorial sum of the currents must be used (IEDs, Metrosil and resistor currents are resistive). The current measurement is insensitive to DC component in fault current to allow a use of only the AC components of the fault current in the above calculations.

The voltage dependent resistor (Metrosil) characteristic is shown in figure 47.

A shunt can be added in parallel to the non-linear resistor in order to desensitize the function.

Series resistor thermal capacity

The series resistor is dimensioned for 200 W. Care shall be exercised while testing to ensure that if current needs to be injected continuously or for a significant duration of time, check that the heat dissipation in the series resistor does not exceed 200 W. Otherwise injection time shall be reduced to the minimum.

The series resistor is dimensioned for 200 W. The condition: shall be fulfilled. In this condition the continuous injection is allowed during testing.

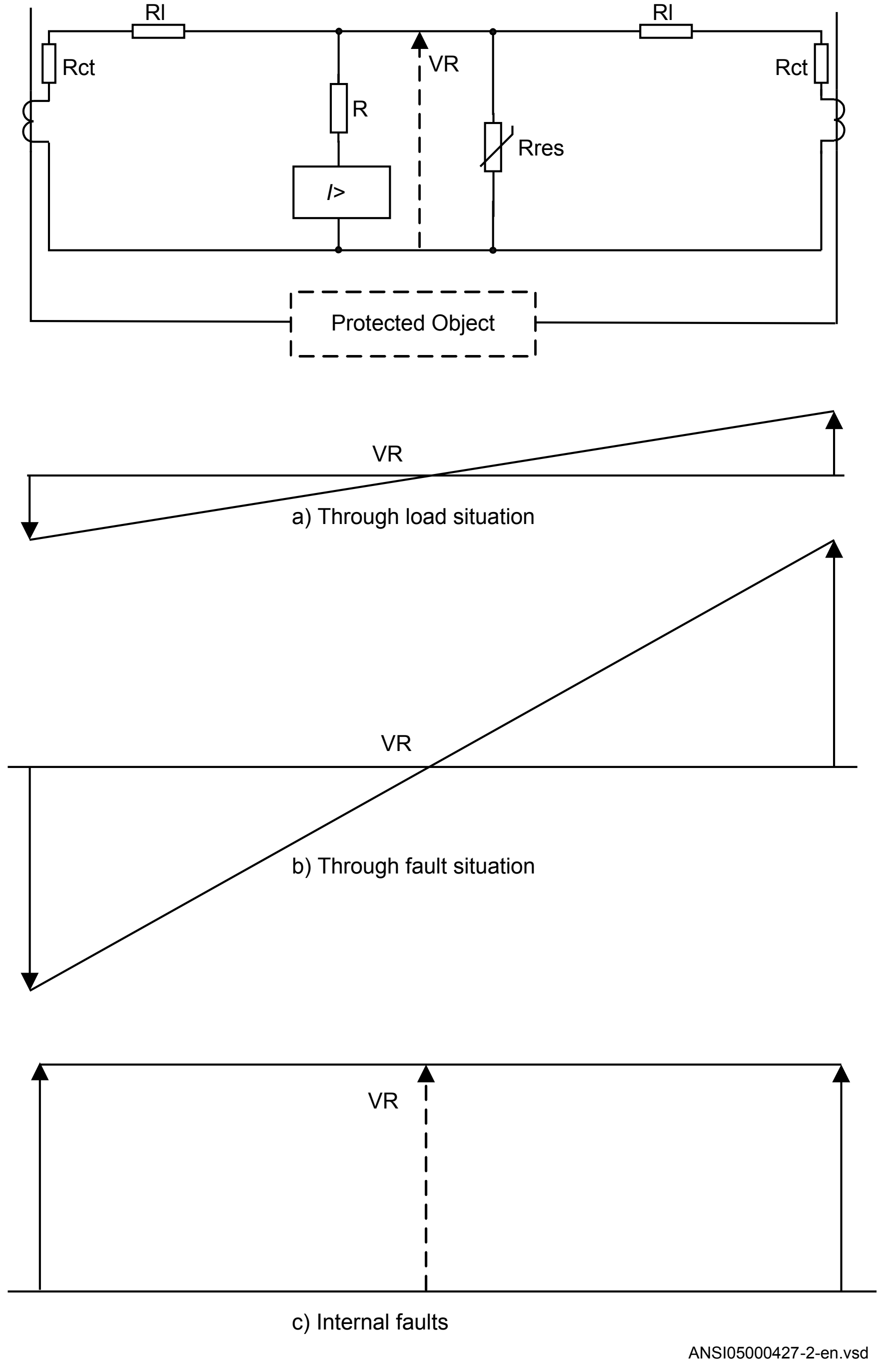

Figure 44: The high impedance principle for one phase with two current transformer inputs

6.2.3 Connection examples for high impedance differential protection

WARNING! USE EXTREME CAUTION! Dangerously high voltages might be present on this equipment, especially on the plate with resistors. Do any maintenance ONLY if the primary object protected with this equipment is de-energized. If required by national law or standard, enclose the plate with resistors with a protective cover or in a separate box.

6.2.3.1 Connections for 1Ph restricted earth fault and high impedance differential protection

Restricted earth fault protection REF (87N) is a typical application for 1Ph High impedance differential protection HZPDIF (87). Typical CT connections for high impedance based REF (87N) protection scheme are shown in figure 45.

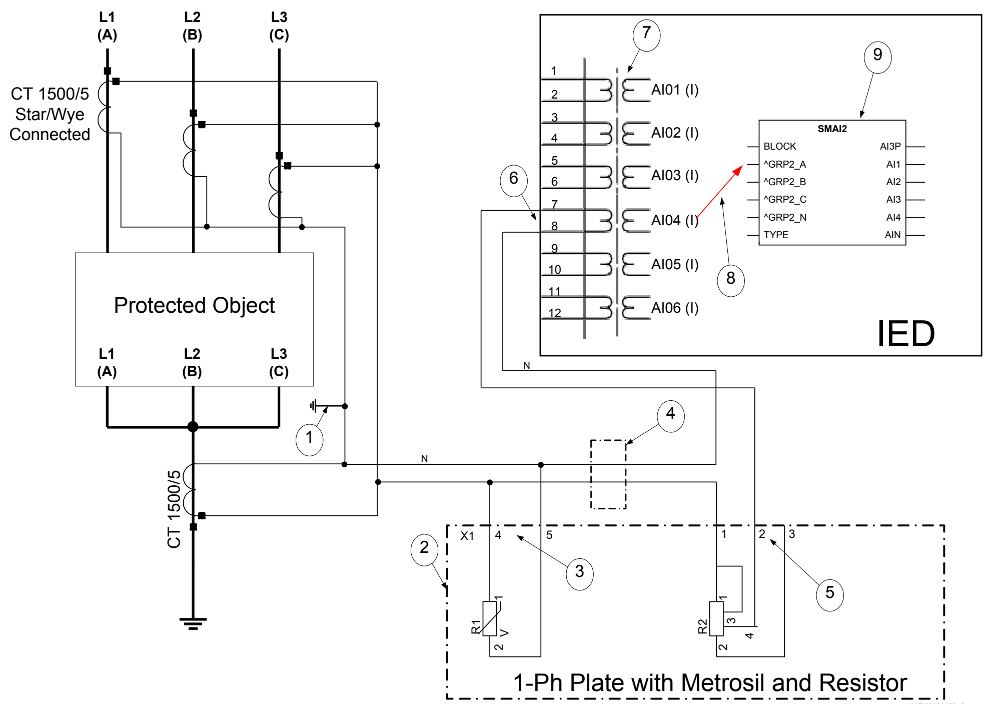

Figure 45: CT connections for restricted earth fault protection

Pos	Description
1	Scheme grounding point

Note that it is of outmost importance to insure that only one grounding point exist in such scheme.

Pos	Description
2	One-phase plate with stabilizing resistor and metrosil.
3	Necessary connection for the metrosil. Shown connections are applicable for both types of one-phase plate.
4	Position of optional test switch for secondary injection into the high impedance differential IED.
5	Necessary connection for stabilizing resistor. Shown connections are applicable for both types of one-phase plate.
6	How to connect REFPDIF (87N) high impedance scheme to one CT input in IED.
7	Transformer input module where this current input is located.

Note that the CT ratio for high impedance differential protection application must be set as one.

- For main CTs with 1A secondary rating the following setting values shall be entered: *CTprim = 1A* and *CTsec = 1A*
- For main CTs with 5A secondary rating the following setting values shall be entered: *CTprim = 5A* and *CTsec = 5A*
- The parameter *CTStarPoint* shall always be left to the default value *ToObject*

Pos	Description
8	Connection made in the Signal Matrix, which connects this current input to first input channel of the preprocessing function block (9). For high impedance differential protection preprocessing function block in 3ms task shall be used.
9	Preprocessing block, which has a task to digitally filter the connected analogue inputs. Preprocessing block output AI1 shall be connected to one instances of 1Ph high impedance differential protection function HZPDIF (87) (for example, instance 1 of HZPDIF (87) in the configuration tool).

6.2.4 Setting guidelines

The setting calculations are individual for each application. Refer to the different application descriptions below.

6.2.4.1 Configuration

The configuration is done in the Application Configuration tool. For example, signals from external check criteria shall be connected to the inputs as required for the application.

BLOCK input is used to block the function for example, from external check criteria.

BLKTR input is used to block the function tripping for example, from external check criteria. The alarm level will be operative.

6.2.4.2 Settings of protection function

Operation: The operation of the high impedance differential function can be switched *Enabled* or *Disabled*.

AlarmPickup: Set the alarm level. The sensitivity can roughly be calculated as a divider from the calculated sensitivity of the differential level. A typical setting is 10% of *TripPickup*. It can be used as scheme supervision stage.

tAlarm: Set the time for the alarm. A typical setting is 2-3 seconds.

TripPickup: Set the trip level according to the calculations in the examples for each application example. The level is selected with margin to the calculated required voltage to achieve stability. Values can be 20-200 V dependent on the application.

R series: Set the value of the stabilizing series resistor. Calculate the value according to the examples for each application. Adjust the resistor as close as possible to the calculated example. Measure the value achieved and set this value here.

The value shall always be high impedance. This means for example, for 1A circuits say bigger than 400 ohms (400 VA) and for 5 A circuits say bigger than 100 ohms (2500 VA). This ensures that the current will circulate and not go through the differential circuit at through faults.

6.2.4.3 Restricted earth fault protection REFPDIF (87N)

For solidly grounded systems a Restricted earth fault protection REF (87N) is often provided as a complement to the normal transformer differential IED. The advantage with the restricted ground fault IEDs is their high sensitivity. Sensitivities of 2-8% can be achieved whereas the normal differential IED will have sensitivities of 20-40%. The level for high impedance restricted ground fault function is dependent of the current transformers magnetizing currents.

Restricted ground fault IEDs are also very quick due to the simple measuring principle and the measurement of one winding only.

The connection of a restricted earth fault IED is shown in figure 46. It is connected across each directly or low ohmic grounded transformer winding in figure 46.

It is quite common to connect the restricted earth fault IED in the same current circuit as the transformer differential IED. This will due to the differences in measuring

principle limit the possibility for the differential IEDs to detect ground faults. Such faults are then only detected by REF (87N) function. The mixed connection using the 1Ph High impedance differential protection HZPDIF (87) function should be avoided and the low impedance scheme should be used instead.

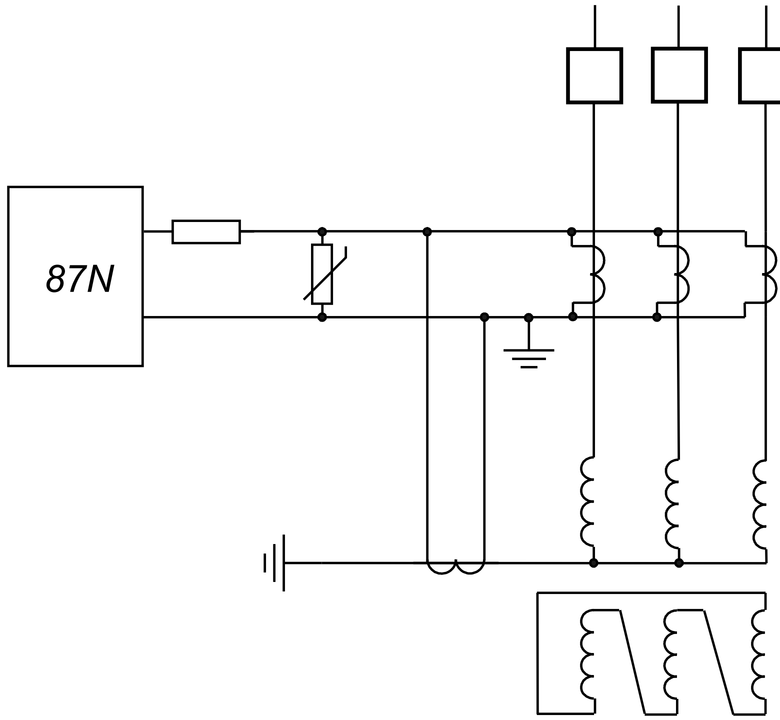

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Figure 46: Application of HZPDIF (87) function as a restricted earth fault IED for an YNd transformer

Setting example

It is strongly recommended to use the highest tap of the CT whenever high impedance protection is used. This helps in utilizing maximum CT capability, minimize the current, thereby reducing the stability voltage limit. Another factor is that during internal faults, the voltage developed across the selected tap is limited by the non-linear resistor but in the unused taps, owing to auto-transformer action, voltages much higher than design limits might be induced.

Basic data:	
Transformer rated current on HV winding:	250 A
Current transformer ratio:	600-300/5A A (Note: Must be the same at all locations)
CT Class:	C200
Cable loop resistance:	<50 ft AWG10 (one way between the junction point and the farthest CT) to be limited to approx. 0.05 Ohms at 75deg C gives loop resistance 2 · 0.05 = 0.1 Ohms
Max fault current:	The maximum through fault current is limited by the transformer reactance, use 15 · rated current of the transformer

Calculation:

$$VR > 15 \cdot \frac{250}{600/5} \cdot (0.1 + 0.1) = 6.25V$$

(Equation 17)

Select a setting of *TripPickup*=20 V.

The current transformerknee point voltage can roughly be calculated from the rated values. Considering knee point voltage to be about 70% of the accuracy limit voltage.

$$VkneeANSI > (0.1 + 2) \cdot 100 = 210V$$

(Equation 18)

that is, greater than 2 · *TripPickup*

Check from the table of selected resistances the required series stabilizing resistor value to use. As this application it is required to be so sensitive so select *R series*= 100 ohm which gives a current of 200 mA.

To calculate the sensitivity at operating voltage, refer to equation 19 which is acceptable as it gives around 10% minimum operating current, ignoring the current drawn by the non-linear resistor.

$$IP = \frac{600}{5} \cdot \left(200\underline{|0°} + 4 \cdot 20\underline{|-60°}\right) \leq approx.5.4A$$

(Equation 19)

Where 200mA is the current drawn by the IED circuit and 50mA is the current drawn by each CT just at pickup. The magnetizing current is taken from the magnetizing curve for the current transformer cores which should be available. The value at *TripPickup* is taken.

6.2.4.4 Alarm level operation

The 1Ph High impedance differential protection HZPDIF (87) function has a separate alarm level, which can be used to give alarm for problems with an involved current transformer circuit. The setting level is normally selected to be around 10% of the operating voltage *TripPickup*.

The setting of V> Alarm is related to the value of the stabilizing resistor and the minimum current sensitivity. The setting example shows the calculation procedure of the setting value of V> Alarm.

As seen in the setting examples above the sensitivity of HZPDIF (87) function is normally high, which means that the function will in many cases operate also for short circuits or open current transformer secondary circuits. However the stabilizing resistor can be selected to achieve sensitivity higher than normal load current and/or separate criteria can be added to the operation, a check zone. This can be either another IED, with the same HZPDIF (87) function, or be a check about the fault condition, which is performed by a ground overcurrent function or neutral point voltage function.

For such cases where operation is not expected during normal service the alarm output should be used to activate an external shorting of the differential circuit avoiding continuous high voltage in the circuit. A time delay of a few seconds is used before the shorting and alarm are activated. Auxiliary relays with contacts that can withstand high voltage shall be used, like RXMVB types. Use auxiliary relays with contacts that can withstand high voltages for example, RXMVB types.

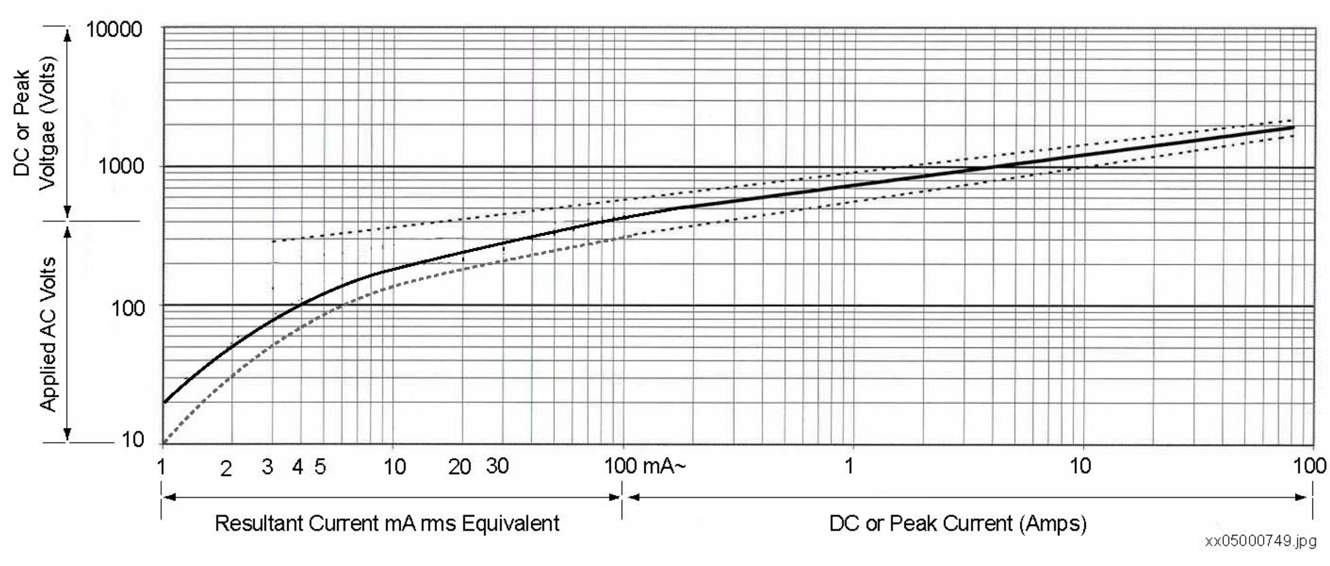

Figure 47: Current voltage characteristics for the non-linear resistors, in the range 10-200 V, the average range of current is: 0.01–10 mA

6.3 Generator differential protection GENPDIF (87G)

6.3.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Generator differential protection	GENPDIF	$I_d>$	87G

6.3.2 Application

Short circuit between the phases of the stator windings causes normally very large fault currents. The short circuit generates risk of damages on insulation, windings and stator core. The large short circuit currents cause large current forces, which can damage other components in the power plant, such as turbine and generator-turbine shaft. The short circuit can also initiate explosion and fire. When a short circuit occurs in a generator there is a damage that has to be repaired. The severity and thus the repair time are dependent on the degree of damage, which is highly dependent on the fault time. Fast fault clearance of this fault type is therefore of greatest importance to limit the damages and thus the economic loss.

To limit the damages in connection to stator winding short circuits, the fault clearance time must be as fast as possible (instantaneous). Both the fault current contributions from the external power system (via the generator and/or the block circuit breaker) and from the generator itself must be disconnected as fast as possible. A fast reduction of the mechanical power from the turbine is of great importance. If the generator is connected to the power system close to other generators, the fast fault clearance is essential to maintain the transient stability of the non-faulted generators.

Normally, the short circuit fault current is very large, that is, significantly larger than the generator rated current. There is a risk that a short circuit can occur between phases close to the neutral point of the generator, thus causing a relatively small fault current. The fault current fed from the generator itself can also be limited due to low excitation of the generator. This is normally the case at running up of the generator, before synchronization to the network. Therefore, it is desired that the detection of generator phase-to-phase short circuits shall be relatively sensitive, thus detecting small fault currents.

It is also of great importance that the generator short circuit protection does not trip for external faults, when large fault current is fed from the generator. In order to combine

fast fault clearance, sensitivity and selectivity the Generator current differential protection GENPDIF (87G) is normally the best choice for phase-to-phase generator short circuits.

The risk of unwanted operation of the differential protection, caused by current transformer saturation, is a universal differential protection problem. If the generator is tripped in connection to an external short circuit, this can first give an increased risk of power system collapse. Besides that, there can be a production loss for every unwanted trip of the generator. Hence, there is a great economic value to prevent unwanted disconnection of power generation.

The generator application allows a special situation, where the short circuit fault current with a large DC component, can have the first zero crossing of the current, after several periods. This is due to the long DC time constant of the generator (up to 1000 ms), see figure 48.

GENPDIF (87G) is also well suited to give fast, sensitive and selective fault clearance, if used for protection of shunt reactors and small busbars.

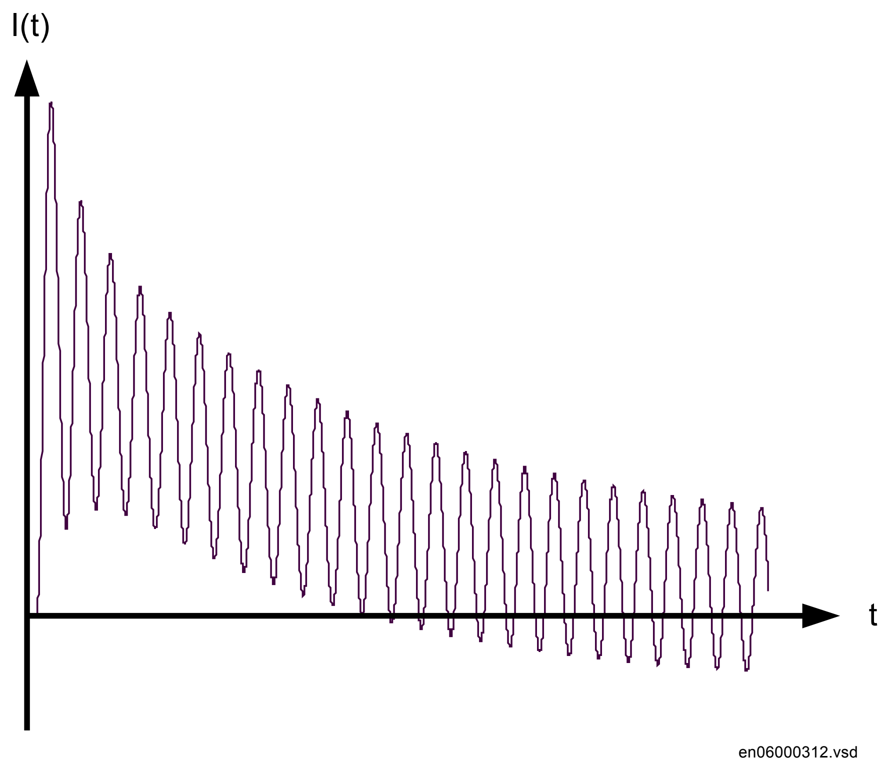

Figure 48: Typical for generators are long DC time constants. Their relation can be such that the instantaneous fault current is more than 100 % offset in the beginning.

6.3.3 Setting guidelines

Generator differential protection GENPDIF (87G) makes evaluation in different sub-functions in the differential function.

- Percentage restrained differential analysis
- DC, 2nd and 5th harmonic analysis
- Internal/external fault discriminator

Adaptive frequency tracking must be properly configured and set for the Signal Matrix for analog inputs (SMAI) preprocessing blocks in order to ensure proper operation of the generator differential protection function during varying frequency conditions.

6.3.3.1 General settings

GlobalBaseSel: Selects the global base value group used by the function to define (*IBase*), (*VBase*) and (*SBase*).

IBase is set to the rated current of the generator, set in primary A.

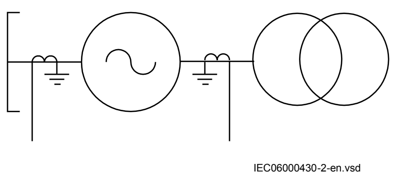

Figure 49: Position of current transformers

If Generator differential protection GENPDIF (87G) is used in conjunction with a transformer differential protection, the direction of the terminal CT may be referred to the transformer differential protection. This will give wrong reference direction of the generator IED side CT. This can be adjusted by setting the *Negation* parameter of the used SMAI block to Negate3Ph+N.

Operation: GENPDIF (87G) is set *Enabled* or *Disabled* with this setting.

6.3.3.2 Percentage restrained differential operation

The characteristic of the restrain differential protection is shown in figure 50. The characteristic is defined by the settings:

- *IdMin*
- *EndSection1*
- *EndSection2*
- *SlopeSection2*
- *SlopeSection3*

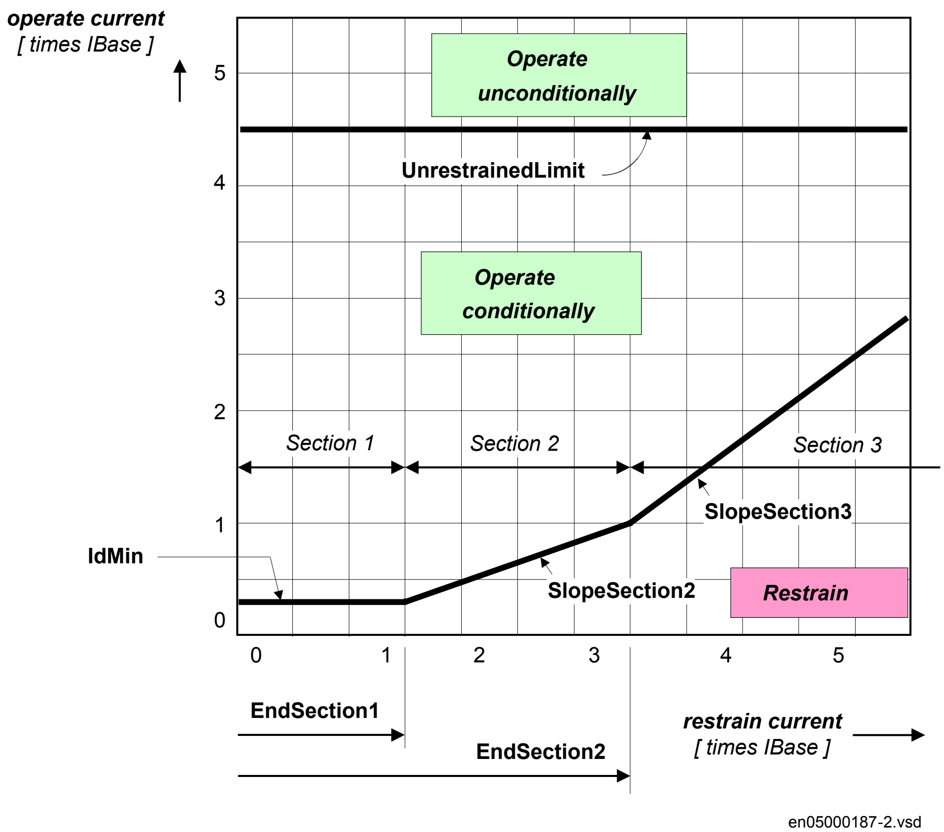

Figure 50: Operate-restrain characteristic

$$slope = \frac{\Delta Ioperate}{\Delta Irestrain} \cdot 100\%$$

(Equation 20)

IdMin: *IdMin* is the constant sensitivity of section 1. This setting can normally be chosen to 0.10 times the generator rated current.

In section 1 the risk of false differential current is very low. This is the case, at least up to 1.25 times the generator rated current. *EndSection1* is proposed to be set to 1.25 times the generator rated current.

In section 2, a certain minor slope is introduced which is supposed to cope with false differential currents proportional to higher than normal currents through the current transformers. *EndSection2* is proposed to be set to about 3 times the generator rated current. The *SlopeSection2*, defined as the percentage value of $\Delta I_{diff}/\Delta I_{Bias}$, is proposed to be set to 40%, if no deeper analysis is done.

In section 3, a more pronounced slope is introduced which is supposed to cope with false differential currents related to current transformer saturation. The *SlopeSection3*, defined as the percentage value of $\Delta I_{diff}/\Delta I_{Bias}$, is proposed to be set to 80 %, if no deeper analysis is done.

IdUnre: *IdUnre* is the sensitivity of the unrestrained differential protection stage. The choice of setting value can be based on calculation of the largest short circuit current from the generator at fault in the external power system (normally three-phase short circuit just outside of the protection zone on the LV side of the step-up transformer). *IdUnre* is set as a multiple of the generator rated current.

OpCrossBlock: If *OpCrossBlock* is set to *Yes*, and PICKUP signal is active, activation of the harmonic blocking in that phase will block the other phases as well.

6.3.3.3 Negative sequence internal/external fault discriminator feature

OpNegSeqDiff: *OpNegSeqDiff* is set to *Yes* for activation of the negative sequence differential features, both the internal or external fault discrimination and the sensitive negative sequence differential current feature. It is recommended to have this feature enabled.

IMinNegSeq: *IMinNegSeq* is the setting of the smallest negative sequence current when the negative sequence based functions shall be active. This sensitivity can normally be set down to 0.04 times the generator rated current, to enable very sensitive protection function. As the sensitive negative sequence differential protection function is blocked at high currents the high sensitivity does not give risk of unwanted function.

NegSeqROA: *NegSeqROA* is the “Relay Operate Angle”, as described in figure 51.

The default value 60° is recommended as optimum value for dependability and security.

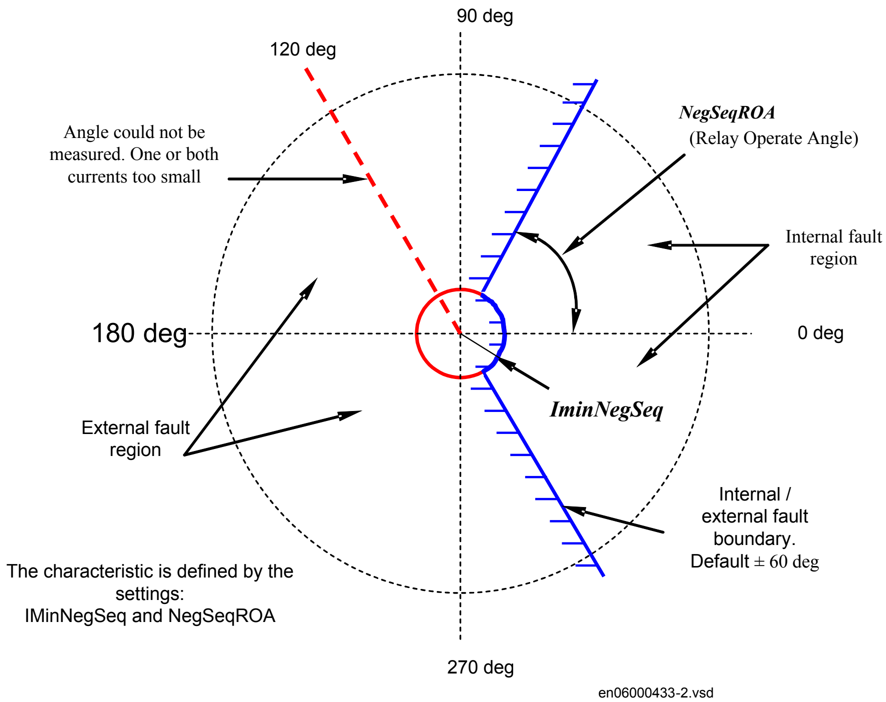

Figure 51: NegSeqROA: NegSeqROA determines the boundary between the internal- and external fault regions

6.3.3.4 Other additional options

HarmDistLimit: This setting is the total harmonic distortion (2^{nd} and 5^{th} harmonic) for the harmonic restrain pick-up. The default limit 10% can be used in normal cases. In special application, for example, close to power electronic converters, a higher setting might be used to prevent unwanted blocking.

TempIdMin: If the binary input raise pick-up (DESENSIT) is activated the operation level of *IdMin* is increased to the *TempIdMin*.

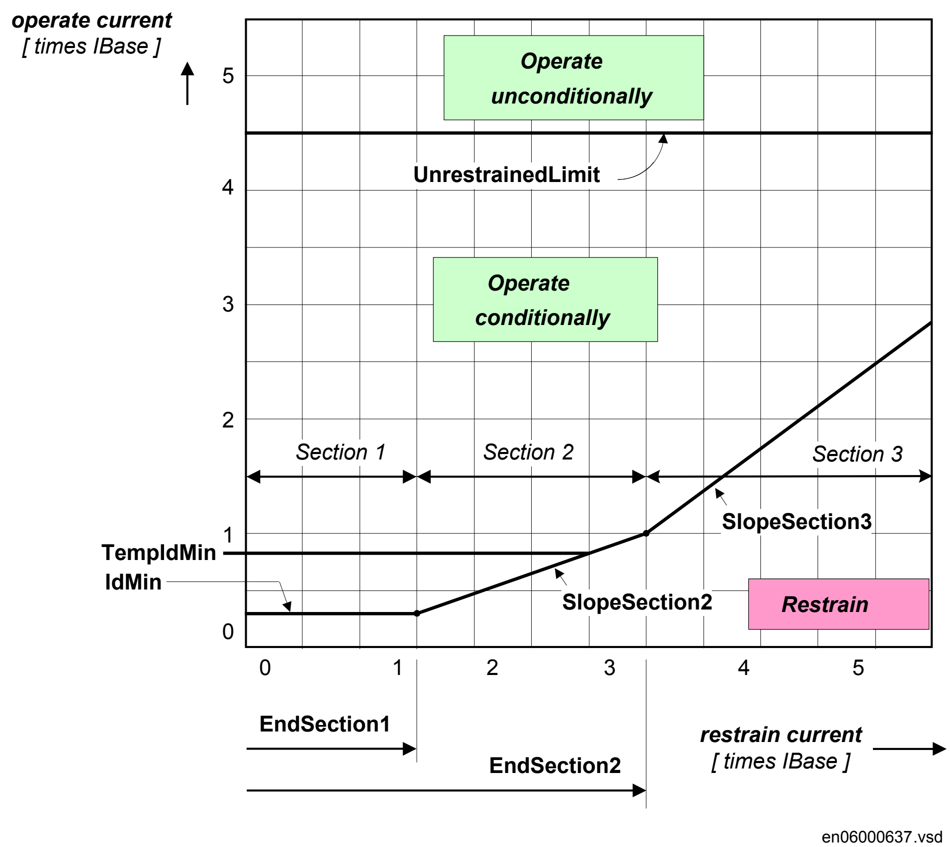

Figure 52: The value of TempIdMin

AddTripDelay: If the input DESENSIT is activated the operation time of the protection function can also be increased by the setting *AddTripDelay*.

OperDCBiasing: If enabled the DC component of the differential current will be included in the bias current with a slow decay. The option can be used to increase security if the primary system DC time constant is very long, thus giving risk of current transformer saturation, even for small currents. It is recommended to set *OperDCBiasing* = *Enabled* if the current transformers on the two sides of the generator are of different make with different magnetizing characteristics. It is also recommended to set the parameter *OperDCBiasing* = *Enabled* for all shunt reactor applications.

6.3.3.5 Open CT detection

The Generator differential function has a built-in, advanced open CT detection feature. This feature can block the unexpected operation created by the Generator differential function in case of open CT secondary circuit under normal load condition. An alarm

signal can also be issued to substation operational personal to make remedy action once the open CT condition is detected.

The following settings parameters are related to this feature:

- Setting parameter *OpenCTEnable* enables/disables this feature
- Setting parameter *tOCTAlarmDelay* defines the time delay after which the alarm signal will be given
- Setting parameter *tOCTReset* defines the time delay after which the open CT condition will reset once the defective CT circuits have been rectified
- Once the open CT condition has been detected, then all the differential protection functions are blocked except the unrestraint (instantaneous) differential protection

The outputs of open CT condition related parameters are listed below:

- *OpenCT*: Open CT detected
- *OpenCTAlarm*: Alarm issued after the setting delay
- *OpenCTIN*: Open CT in CT group inputs (1 for input 1 and 2 for input 2)
- *OpenCTPH*: Open CT with phase information (1 for phase A, 2 for phase B, 3 for phase C)

Section 7 Impedance protection

7.1 Underimpedance protection for generators and transformers ZGCPDIS (21G)

7.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Underimpedance protection for generators and transformers	ZGCPDIS	Z<	21G

7.1.2 Application

In the case of a static excitation system, receiving its power from the generator terminals, the magnitude of a sustained phase-to-phase short-circuit current depends on the generator terminal voltage. In case of a nearby multi-phase fault, the generator terminal voltage may drop to quite low level (for example <25%) and the generator fault current may consecutively fall below the pickup of the overcurrent relay. The short-circuit current may drop below rated current after 0.5 - 1 s also for generators with excitation system not fed from the generator terminals if the fault occurs when the automatic voltage regulator is out of service. The under impedance protection is then the best generator backup protection which can be used under such circumstances. For this reason, an impedance measuring relay is generally recommended for generator back-up short-circuit protection.

The impedance relay is normally connected to current transformers on the generator neutral side to provide back-up also when the generator is disconnected from the system. At reduced voltages, the current required for operation will be reduced. At zero voltage, operation is obtained with a current bigger than 15 % of *IBase* (that is, generator rated current).

The underimpedance protection for generators and transformers function (ZGCPDIS, 21G) in the 650 series is designed to meet basic requirements for application as backup protection for generators and transformers.

7.1.3 Setting guidelines

The settings for the underimpedance function are done in primary ohms. The instrument transformer ratios that have been set for the analogue input module is used to automatically convert the measured secondary input signals to primary values used in ZGCPDIS (21G).

The following basics must be considered, depending on the application, when calculating the setting values:

- Errors introduced by current and voltage instrument transformers, particularly under transient conditions.

The setting values of all parameters that belong to ZGCPDIS (21G) must correspond to the parameters of the protected object and coordinated to the selectivity plan for the network.

GlobalBaseSel: Selects the global base value group used by the function to define (*IBase*), (*VBase*) and (*SBase*).

For ZGCPDIS (21G) function always use Global base values which setting correspond to the generator rated data.

ZGCPDIS (21G) function has an offset mho characteristic and it only evaluates three phase-to-phase impedance measuring loops. It has a forward and reverse impedance setting according to figure 53.

The relevant phase-to-phase measuring loop is released as soon as the measured current is above 15% of *IBase*.

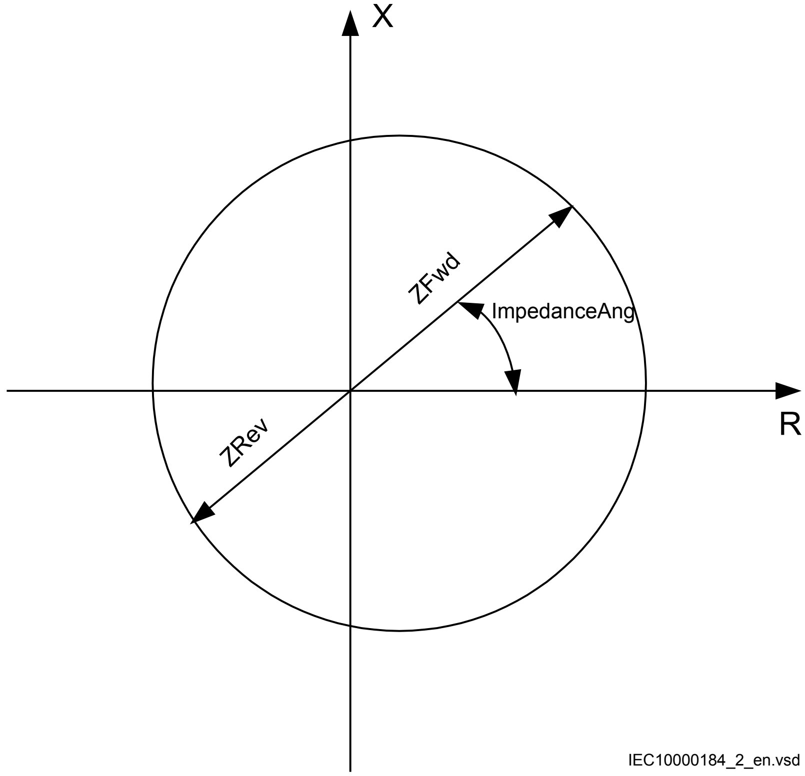

Figure 53: Operating characteristic for phase-to-phase loops

7.2 Loss of excitation LEXPDIS(40)

7.2.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Loss of excitation	LEXPDIS	Φ<	40

7.2.2 Application

There are limits for the low excitation of a synchronous machine. A reduction of the excitation current weakens the coupling between the rotor and the external power system. The machine may lose the synchronism and starts to operate like an induction machine. Then, the reactive consumption will increase. Even if the machine does not lose synchronism it may not be acceptable to operate in this state for a long time. Reduction of excitation increases the generation of heat in the end region of the synchronous machine. The local heating may damage the insulation of the stator winding and even the iron core.

A generator connected to a power system can be represented by an equivalent single phase circuit as shown in figure 54. For simplicity the equivalent shows a generator having round rotor, ($X_d \approx X_q$).

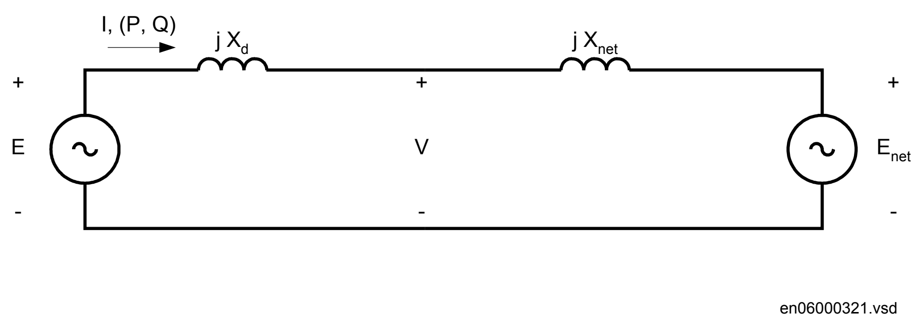

Figure 54: A generator connected to a power system, represented by an equivalent single phase circuit

where:

E	represents the internal voltage in the generator,
X_d	is the stationary reactance of the generator,
X'_d	is the sub-transient reactance of the generator,
X_{net}	is an equivalent reactance representing the external power system and
E_{net}	is an infinite voltage source representing the lumped sum of the generators in the system.
Xq	quadrature axis reactance of the generator

The active power out from the generator can be formulated according to equation 21:

$$P = \frac{E \cdot E_{net}}{X_d + X_{net}} \cdot \sin\delta$$

(Equation 21)

where:

The angle δ is the phase angle difference between the voltages E and E_{net}.

If the excitation of the generator is decreased (loss of field), the voltage E becomes low. In order to maintain the active power output the angle δ must be increased. It is obvious that the maximum power is achieved at 90°. If the active power cannot be reached at 90º static stability cannot be maintained.

The complex apparent power from the generator, at different angles δ is shown in figure 55. The line corresponding to 90° is the steady state stability limit. It must be noticed that the power limitations shown below is highly dependent on the network impedance.

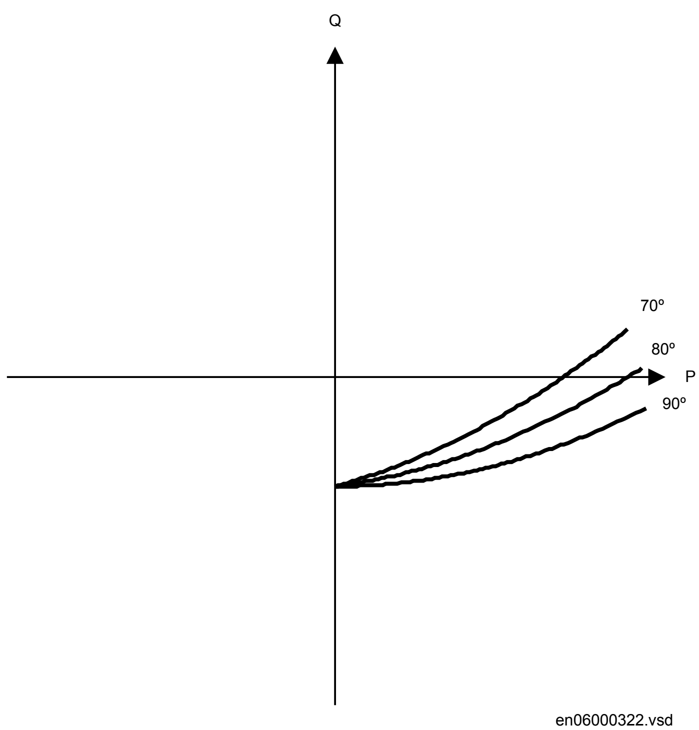

Figure 55: The complex apparent power from the generator, at different angles δ

To prevent damages to the generator block, the generator should be tripped when the excitation becomes too low.. A suitable area, in the PQ-plane, for protection operation

is shown in figure 56. In this example limit is set to a small negative reactive power independent of active power.

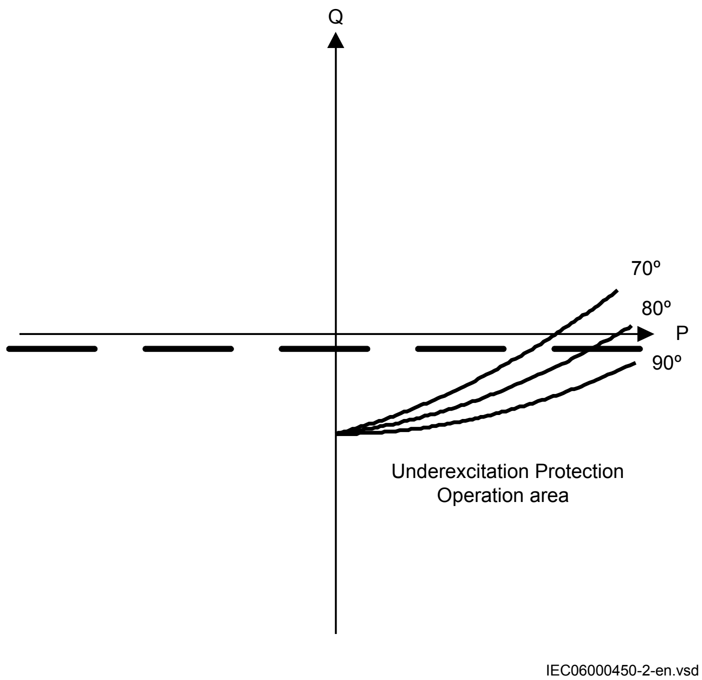

Figure 56: Suitable area, in the PQ-plane, for protection operation

Often the capability curve of a generator describes also the low excitation capability of the generator, see figure 57.

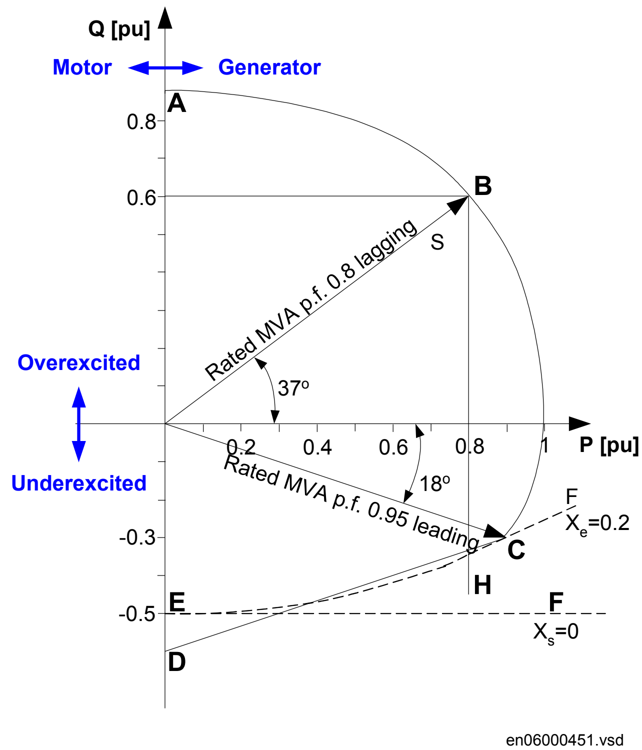

Figure 57: Capability curve of a generator

where:

AB	=	Field current limit
BC	=	Stator current limit
CD	=	End region heating limit of stator, due to leakage flux
BH	=	Possible active power limit due to turbine output power limitation
EF	=	Steady-state limit without AVR
X_s	=	Source impedance of connected power system

Loss of excitation protection can be based on directional power measurement or impedance measurement.

The straight line EF in the P-Q plane can be transferred into the impedance plane by using the relation shown in equation 22.

$$\overline{Z} = \frac{\overline{V}}{\overline{I}} = \frac{\overline{V} \cdot \overline{V}^*}{\overline{I} \cdot \overline{V}^*} = \frac{V^2}{S^*} = \frac{V^2 \cdot \overline{S}}{S^* \cdot \overline{S}} = \frac{V^2 \cdot P}{P^2 + Q^2} + j\frac{V^2 \cdot Q}{P^2 + Q^2} = R + jX$$

(Equation 22)

The straight line in the PQ-diagram will be equivalent with a circle in the impedance plane, see figure 58. In this example the circle is corresponding to constant Q, that is, characteristic parallel with P-axis.

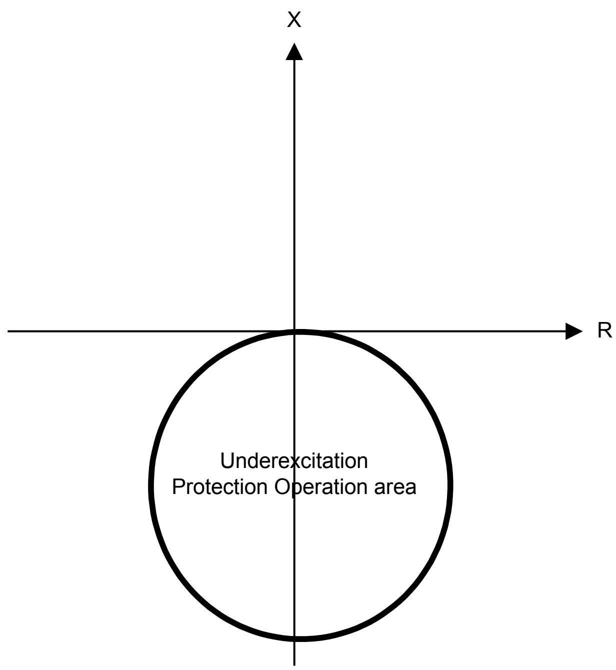

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Figure 58: The straight line in the PQ-diagram is equivalent with a circle in the impedance plane

LEXPDIS (40) in the IED is realised by two impedance circles and a directional restraint possibility as shown in figure 59.

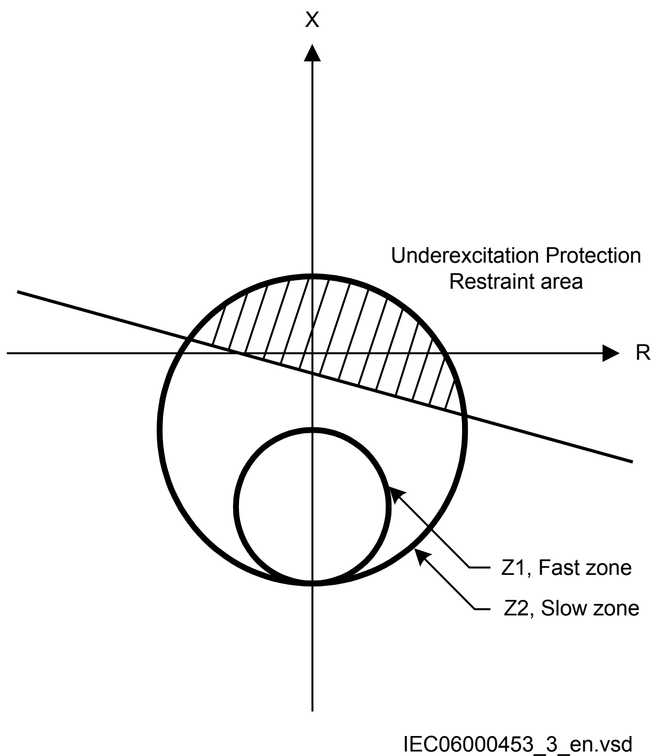

Figure 59: LEXPDIS (40) in the IED, realized by two impedance circles and a directional restraint possibility

7.2.3 Setting guidelines

Here is described the setting when there are two zones activated of the protection. Zone Z1 will give a fast trip in case of reaching the dynamic limitation of the stability. Zone 2 will give a trip after a longer delay if the generator reaches the static limitation of stability. There is also a directional criterion used to prevent trip at close in external faults in case of zones reaching into the impedance area as shown in figure 59.

Operation: With the setting *Operation* LEXPDIS (40) function can be set *Enabled*/*Disabled*.

Common base IED values for primary current (setting *IBase*), primary voltage (setting *VBase*) and primary power (setting *SBase*) are set in a Global base values for settings function *GBASVAL*. Setting *GlobalBaseSel* is used to select a *GBASVAL* function for reference of base values.

IBase: The setting *IBase* is set to the generator rated Current in A, see equation 23.

$$IBase = \frac{S_N}{\sqrt{3} \cdot V_N}$$

(Equation 23)

VBase: The setting *VBase* is set to the generator rated Voltage (phase-phase) in kV.

OperationZ1, *OperationZ2*: With the settings*OperationZ1* and *OperationZ2* each zone can be set *Enabled* or *Disabled*.

For the two zones the impedance settings are made as shown in figure 60.

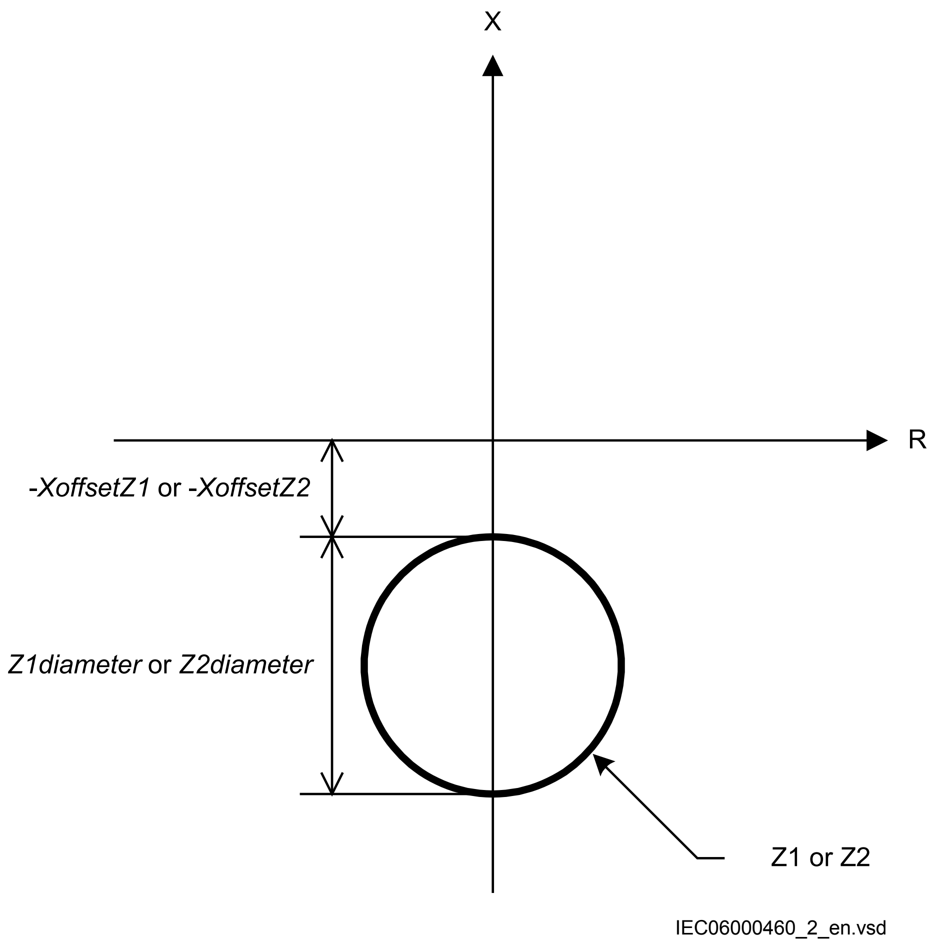

Figure 60: Impedance settings for the fast (Z1) and slow (Z2) zone

The impedances are given in pu of the base impedance calculated according to equation 24.

$$Z_{Base} = \frac{VBase/\sqrt{3}}{IBase}$$

(Equation 24)

XoffsetZ1 and *XoffsetZ2*, offset of impedance circle top along the X axis, are given negative value if X < 0.

XoffsetZ1: It is recommended to set *XoffsetZ1*= - X_d'/2 and *Z1diameter* = 100% of ZBase.

tZ1: *tZ1* is the setting of trip delay for Z1 and this parameter is recommended to set 0.1 s.

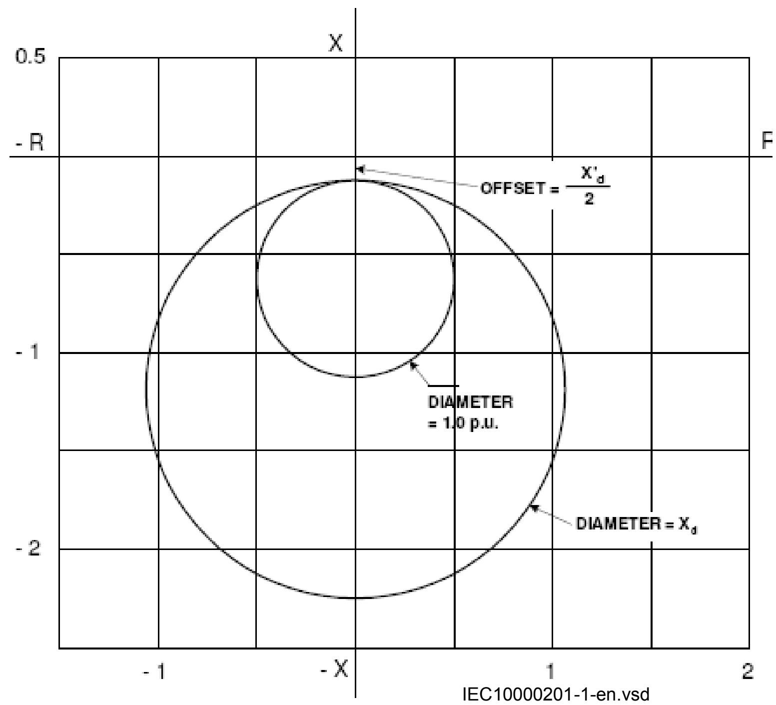

Figure 61: Loss of excitation characteristics recommended by IEEE

It is recommended to set *XoffsetZ2* equal to - X_d'/2 and *Z2diamater* equal to X_d.

tZ2: *tZ2* is the setting of trip delay for Z2 and this parameter is recommended to set 2.0 s not to risk unwanted trip at oscillations with temporary apparent impedance within the characteristic.

DirSuperv: The directional restrain characteristic allows impedance setting with positive X value without the risk of unwanted operation of the under-excitation

function. To enable the directional restrain option the parameter *DirSuperv* shall be set *Enabled*.

XoffsetDirLine, *DirAngle*: The settings *XoffsetDirLine* and *DirAngle* are shown in figure 62. *XoffsetDirLine* is set in % of the base impedance according to equation 24.

XoffsetDirLine is given a positive value if X > 0. *DirAngle* is set in degrees with negative value in the 4th quadrant. Typical value is -13°.

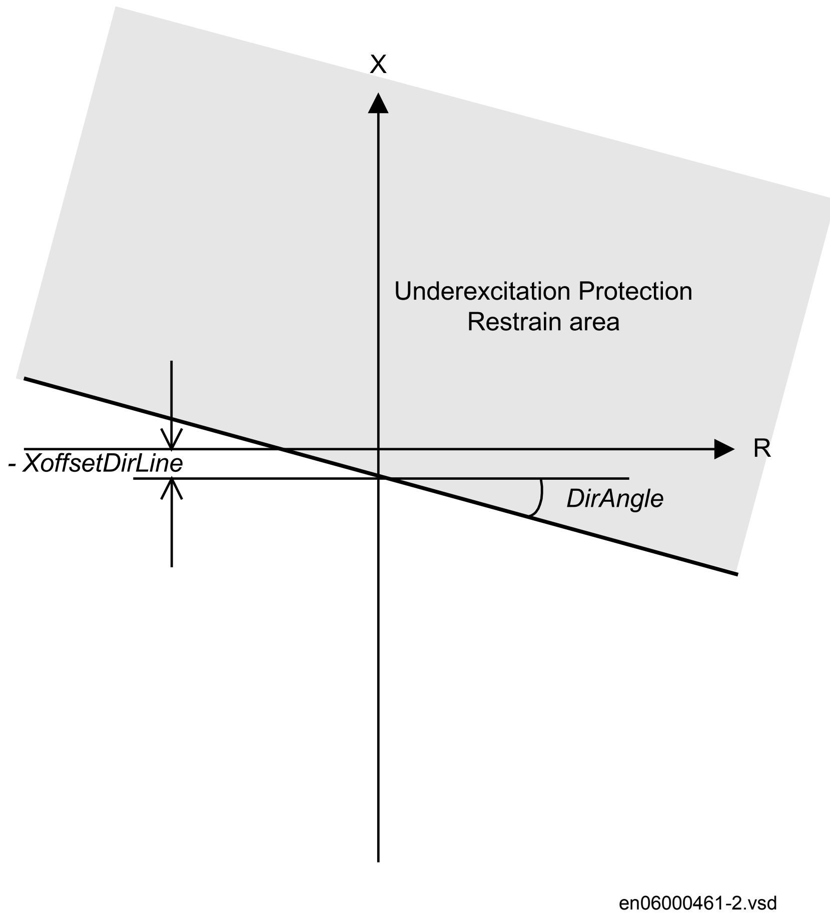

Figure 62: The settings XoffsetDirLine and DirAngle

7.3 Out-of-step protection OOSPPAM (78)

7.3.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Out-of-step protection	OOSPPAM	$\Phi<$	78

7.3.2 Application

Under balanced and stable conditions, a generator operates with a constant rotor (power) angle, delivering to the power system active electrical power which is equal to the mechanical input on the generator axis, minus the small losses in the generator. In the case of a three-phase fault electrically close to the generator, no active power can be delivered. Almost all mechanical power from the turbine is under this condition used to accelerate the moving parts, that is, the rotor and the turbine. If the fault is not cleared quickly, the generator may not remain in synchronism after the fault has been cleared. If the generator loses synchronism (Out-of-step) with the rest of the system, pole slipping occurs. This is characterized by a wild flow of synchronizing power, which reverses in direction twice for every slip cycle.

The out-of-step phenomenon occurs when a phase opposition occurs periodically between different parts of a power system. This is often shown in a simplified way as two equivalent generators connected to each other via an equivalent transmission line and the phase difference between the equivalent generators is 180 electrical degrees.

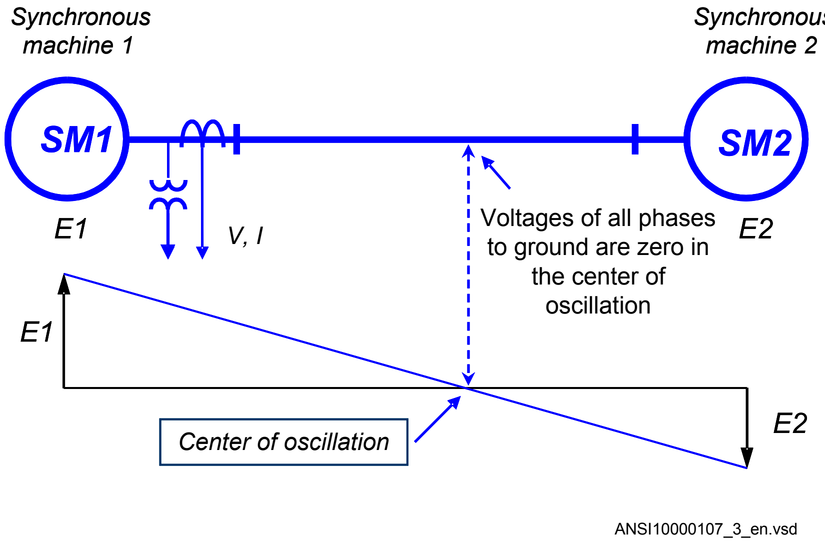

Figure 63: The center of electromechanical oscillation

The center of the electromechanical oscillation can be in the generator unit (or generator-transformer) or out somewhere in the power system. When the center of the electromechanical oscillation occurs within the generator it is essential to trip the generator immediately. If the center of the electromechanical oscillation is found to be outside any of the generators in the power system, the power system should be split into two different parts that each of them has the ability to restore stable operating conditions. This is sometimes called “islanding”. The objective of islanding is to prevent an out-of-step condition from spreading to the healthy parts of the power system. For this purpose, uncontrolled tripping of interconnections or generators must be prevented. It is evident that a reasonable strategy for out-of-step relaying as well as, appropriate choice of other protection relays, their locations and settings require detailed stability studies for each particular power system and/or sub-system. On the other hand, if severe swings occur, from which a fast recovery is improbable, an attempt should be made to isolate the affected area from the rest of the system by opening connections at predetermined points. The electrical system parts swinging to each other can be separated with the line/s closest to the center of the power swing allowing the two systems to be stable as separated islands. The main problem involved with systematic islanding of the system is the difficulty, in some cases, of predicting the optimum splitting points, because they depend on the fault location and the pattern of generation and load at the time. In view of differences in system design, it is hardly possible to state general rules for out-of-step relaying. The reason for the existence of two zones of operation is selectivity, required for successful islanding. If there are several out-of-step relays in the power system, then selectivity between separate relays is obtained by the relay reach (for example zone 1) rather then by time grading.

The out-of-step condition of a generator can be caused by different reasons. Sudden events in an electrical power system such as large changes in load, fault occurrence or slow fault clearance, can cause power oscillations referred to as power swings. In a non-recoverable situation, the power swings become so severe that the synchronism is lost, a condition referred to as pole slipping.

Undamped oscillations occur in the power system, where generator groups at different locations, less strongly connected, oscillate against each other. If the connection between the generators is too weak the magnitude of the oscillations may increase until the angular stability is lost. More often, a three-phase short circuit (unsymmetrical faults are much less dangerous in this respect) may occur in the external power grid, electrically close to the generator. If the fault clearing time is too long, the generator will accelerate so much, that the synchronism cannot be maintained, see figure 64.

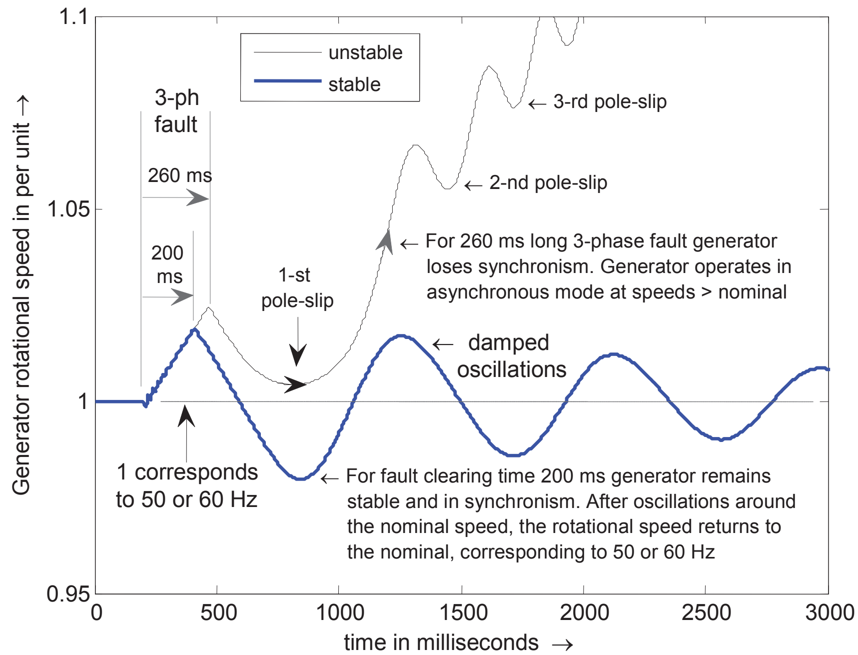

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Figure 64: Stable and unstable case. For the fault clearing time tcl = 200 ms, the generator remains in synchronism, for tcl = 260 ms, the generator loses step.

A generator out-of-step condition, with successive pole slips, can result in damages to the generator, shaft and turbine.

- Stator winding is under high electromechanical stress.
- The current levels under an out-of-step condition can be higher than those under a three-phase fault, there will be significant torque impact on the generator-turbine shaft.
- In asynchronous operation there will be induction of currents in parts of the generator normally not carrying current, thus resulting in increased heating. The consequence can be damages on insulation and stator/rotor iron.

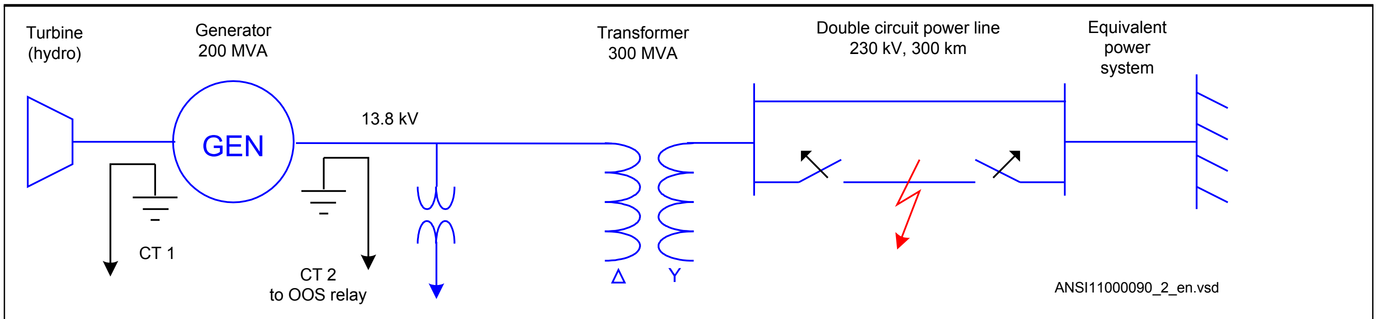
Measurement of the magnitude, direction and rate-of-change of load impedance relative to a generator's terminals provides a convenient and generally reliable means of detecting whether pole-slipping is taking place. The out-of-step protection should protect a generator or motor, (or two weakly connected power systems), against pole-slipping with severe consequences for the machines and stability of the power system. In particular it should:

1. Remain stable for normal steady state load.
2. Distinguish between stable and unstable rotor swings.
3. Locate electrical centre of a swing.
4. Detect the first and the subsequent pole-slips.
5. Take care of the circuit breaker safety.
6. Distinguish between generator-, and motor out-of-step conditions.
7. Provide information for post-disturbance analysis.

7.3.3 Setting guidelines

The setting example for generator protection application shows how to calculate the most important settings *ForwardR*, *ForwardX*, *ReverseR*, and *ReverseX*.

Table 20: An example how to calculate values for the settings ForwardR, ForwardX, ReverseR, and ReverseX



	Generator	Step-up transformer	Single power line	Power system
Data required	VBase = Vgen = 13.8 kV IBase = Igen = 8367 A Xd' = 0.2960 pu Rs = 0.0029 pu	V1 = 13.8 kV V2 = 230 kV I1 = 12 551 A Xt = 0.1000 pu (transf. ZBase) Rt = 0.0054 pu (transf. ZBase)	Vline = 230 kV Xline/km = 0.4289 Ohm/km Rline/km = 0.0659 Ohm/km	Vnom = 230 kV SC level = 5000 MVA SC current = 12 551 A Phi = 84.289° Ze = 10.5801 Ohm

Table continues on next page

1-st step in calculation	ZBase = 0.9522 Ohm (generator) Xd' = 0.2960 · 0.952 = 0.282 Ohm Rs = 0.0029 · 0.952 = 0.003 Ohm	ZBase (13.8 kV) = 0.6348 Ohm Xt = 0.100 · 0.6348 = 0.064 Ohm Rt = 0.0054 · 0.635 = 0.003 Ohm	Xline = 300 · 0.4289 = 128.7 Ohm Rline = 300 · 0.0659 = 19.8 Ohm (X and R above on 230 kV basis)	Xe = Z · sin (Phi) = 10.52 Ohm Re = Z · cos (Phi) = 1.05 Ohm (Xe and Re on 230 kV basis)
2-nd step in calculation	Xd' = 0.2960 · 0.952 = 0.282 Ohm Rs = 0.0029 · 0.952 = 0.003 Ohm	Xt = 0.100 · 0.6348 = 0.064 Ohm Rt = 0.0054 · 0.635 = 0.003 Ohm	Xline= 128.7 · $(13.8/230)^2$ = 0.463 Ohm Rline = 19.8 · $(13.8/230)^2$ = 0.071 Ohm (X and R referred to 13.8 kV)	Xe = 10.52 · $(13.8/230)^2$ = 0.038 Re = 1.05 · $(13.8/230)^2$ = 0.004 (X and R referred to 13.8 kV)
3-rd step in calculation	ForwardX = Xt + Xline + Xe = 0.064 + 0.463 + 0.038 = 0.565 Ohm; ReverseX = Xd' = 0.282 Ohm (all referred to gen. voltage 13.8 kV) ForwardR = Rt + Rline + Re = 0.003 + 0.071 + 0.004 = 0.078 Ohm; ReverseR = Rs = 0.003 Ohm (all referred to gen. voltage 13.8 kV)			
Ready!	ForwardX = 0.565/0.9522 · 100 = 58.39 in % ZBase; ReverseX = 0.282/0.9522 · 100 = 29.62 in % ZBase (all referred to 13.8 kV) ForwardR = 0.078/0.9522 · 100 = 8.19 in % ZBase; ReverseR = 0.003/0.9522 · 100 = 0.32 in % ZBase (all referred to 13.8 kV)			

Settings *ForwardR*, *ForwardX*, *ReverseR*, and *ReverseX*.

- A precondition in order to be able to use the Out-of-step protection and construct a suitable lens characteristic is that the power system in which the Out-of-step protection is installed, is modeled as a two-machine equivalent system, or as a single machine – infinite bus equivalent power system. Then the impedances from the position of the Out-of-step protection in the direction of the normal load flow can be taken as forward.
- The settings *ForwardX*, *ForwardR*, *ReverseX* and *ReverseR* must, if possible, take into account, the post-disturbance configuration of the simplified power system. This is not always easy, in particular with islanding. But for the two machine model as in Table 20, the most probable scenario is that only one line will be in service after the fault on one power line has been cleared by line protections. The settings *ForwardX*, *ForwardR* must therefore take into account the reactance and resistance of only one power line.
- All the reactances and resistances must be referred to the voltage level where the Out-of-step relay is installed; for the example case shown in Table 20, this is the generator nominal voltage VBase = 13.8 kV. This will affect all the forward reactances and resistances in Table 20.
- All reactances and resistances must be finally expressed in percent of ZBase, where ZBase is for the example shown in Table 20 the base impedance of the generator, ZBase = 0.9522 Ohm. Observe that the power transformer's base impedance is different, ZBase = 0.6348 Ohm. Observe that this latter power transformer ZBase = 0.6348 Ohm must be used when the power transformer reactance and resistance are transformed from Ohm to per unit.
- For the synchronous machines as the generator in Table 20, the transient reactance Xd' shall be used. This due to the relatively slow electromagnetic oscillations under out-of-step conditions.
- Sometimes the equivalent resistance of the generator is difficult to get. A good estimate is 1 percent of transient reactance Xd'. No great error is done if this resistance is set to zero (0).
- Inclination of the Zline, connecting points SE and RE, against the real (R) axis can be calculated as arctan ((*ReverseX* + *ForwardX*) / (*ReverseR* + *ForwardR*)), and is

for the case from Table 20 equal to 84.48 degrees, which is a typical value. See for example Table 20.

Other settings:

- *ReachZ1*: Determines the reach of the zone 1 in the forward direction. Determines the position of the X-line which delimits zone 1 from zone 2. Set in % of *ForwardX*. In the case shown in Table 20, where the reactance of the step-up power transformer is 11.32 % of the total *ForwardX*, the setting *ReachZ1* should be set to *ReachZ1 = 12* %. This means that the generator – step-up transformer unit would be in the zone 1. In other words, if the centre of oscillation would be found to be within the zone 1, only a very limited number of pole-slips would be allowed, usually only one.
- *StartAngle*: Angle between the two equivalent rotors, that is, the angle between the two internal induced voltages E1 and E2 in an equivalent simplified two-machine system to get the start signal, in degrees. The width of the lens characteristic is determined by the value of this setting. Whenever the complex impedance Z(R, X) enters the lens, this is a sign of trouble. The angle recommended is 110 or 120 degrees, because it is at this rotor angle where real trouble with dynamic stability usually begins. Power angle 120 degrees is sometimes called “the angle of no return” because if this angle is reached under generator swings, the generator is most likely to lose synchronism. When the complex impedance Z(R, X) enters the lens the start output signal (`PICKUP`) is set to 1 (`TRUE`).
- *tReset*: Interval of time since the last pole-slip detected, when the Out-of-step protection is reset. If there is no more pole slips detected under the time interval specified by *tReset* since the previous one, the function is reset. All outputs are set to 0 (`FALSE`). If no pole slip at all is detected under interval of time specified by tReset since the pickup signal has been set (for example a stable case with synchronism retained), the function is as well reset, which includes the pickup output signal (`PICKUP`), which is reset to 0 (`FALSE`) after *tReset* interval of time has elapsed. However, the measurements of analogue quantities such as R, X, P, Q, and so on continue without interruptions. Recommended setting of tReset is in the range of 6 to 12 seconds.
- *NoOfSlipsZ1*: Maximum number of pole slips with centre of electromechanical oscillation within zone 1 required for a trip. Usually, NoOfSlipsZ1 = 1.
- *NoOfSlipsZ2*: Maximum number of pole slips with centre of electromechanical oscillation within zone 2 required for a trip. The reason for the existence of two zones of operation is selectivity, required particularly for successful islanding. If there are several pole slip (out-of-step) relays in the power system, then selectivity between separate relays is obtained by the relay reach (for example zone 1) rather then by time grading. In a system, as in Table 20, the number of allowed pole slips in zone 2 can be the same as in zone 1, *NoOfSlipsZ1 = 1*. Recommended value: *NoOfSlipsZ2 = 2* or *3*.

- *OperationZ1*: Operation zone 1 *Enabled*, *Disabled*. If *OperationZ1 = Disabled*, all pole-slips with centre of the electro-magnetic oscillation within zone 1 are ignored. Default setting = *Enabled*. More likely to be used is the option to extend zone 1 so that zone 1 even covers zone 2. This feature is activated by the input extendZone1 (EXTZONE1).
- *OperationZ2*: Operation zone 2 *Enabled*, *Disabled*. If *OperationZ1 = Disabled*, all pole-slips with centre of the electro-magnetic oscillation within zone 2 are ignored. Default setting = *Enabled*.
- *tBreaker*: Circuit breaker open-time. Use the default value *tBreaker = 0.000 s* if unknown. If the value is known higher than 0.000 is specified, for example *tBreaker = 0.040 s*, then the out-of-step function will give a trip commands 0.040 seconds before the currents reach their minimum value. This in order to decrease the stress to the circuit breaker.
- *VBase*: This is the voltage at the point where the Out-of-step protection is installed. If the protection is installed on the generator output terminals, then *VBase* is the nominal (rated) phase to phase voltage of the protected generator. All the resistances and reactances are measured and displayed referred to voltage *VBase*. Observe that *ReverseX*, *ForwardX*, *ReverseR*, and *ForwardR* must be given referred to *VBase*.
- *IBase*: Out-of-step protection is installed at generator, then *IBase* is the protected generator nominal (rated) current.

7.4 Load enchroachment LEPDIS

7.4.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Load encroachment	LEPDIS	-	-

7.4.2 Application

Heavy load transfer is common in many power networks and may make fault resistance coverage difficult to achieve. In such a case, Load encroachment (LEPDIS) function can be used to prevent operation of the of the underimpedance measuring zones during heavy loads.

7.4.3 Setting guidelines

7.4.3.1 Resistive reach with load encroachment characteristic

The procedure for calculating the settings for the load encroachment consists basically of defining the load angle *LdAngle* and the blinder *RLd*, as shown in figure 65.

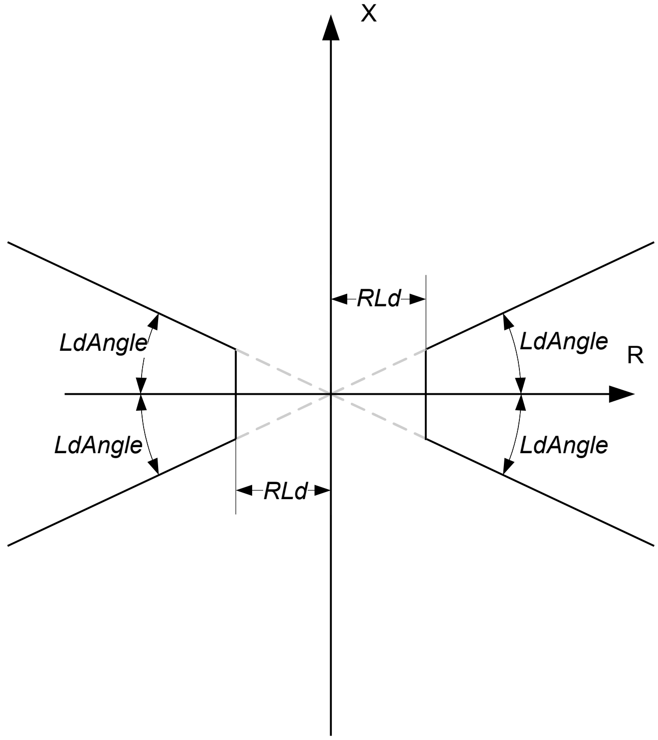


Figure 65: Load encroachment characteristic

The load angle *LdAngle* is the same in forward and reverse direction, so it could be suitable to begin to calculate the setting for that parameter. The parameter is set to the maximum possible load angle at the maximum active load. A value larger than 20° must be used considering a normal PF=0.8 corresponding to an angle of 36 deg.

The blinder, *RLd*, can be calculated according to equation:

$$RLd = 0.8 \cdot \frac{V^2 \min}{P \exp \max}$$

(Equation 25)

where:

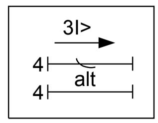
Pexp max	is the maximum exporting active power

*V*min	is the minimum voltage for which the *P*exp max occurs
0.8	is a security factor to ensure that the setting of RLd can be lesser than the calculated minimal resistive load.

Section 8 Current protection

8.1 Four step phase overcurrent protection 3-phase output OC4PTOC (51/67)

8.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Four step phase overcurrent protection 3-phase output	OC4PTOC		51/67

8.1.2 Application

The Four step phase overcurrent protection 3-phase output OC4PTOC (51_67) is used in several applications in the power system. Some applications are:

- Short circuit protection of feeders in distribution and subtransmission systems. Normally these feeders have radial structure.
- Back-up short circuit protection of transmission lines.
- Back-up short circuit protection of power transformers.
- Short circuit protection of different kinds of equipment connected to the power system such as; shunt capacitor banks, shunt reactors, motors and others.
- Back-up short circuit protection of power generators.

If VT inputs are not available or not connected, setting parameter *DirModeSelx* (*x* = step 1, 2, 3 or 4) shall be left to default value *Non-directional*or set to *Disabled*.

In many applications several steps with different current pick up levels and time delays are needed. OC4PTOC (51_67) can have up to four different, individual settable, steps. The flexibility of each step of OC4PTOC (51_67) is great. The following options are possible:

Non-directional / Directional function: In most applications the non-directional functionality is used. This is mostly the case when no fault current can be fed from the protected object itself. In order to achieve both selectivity and fast fault clearance, the directional function can be necessary.

Choice of delay time characteristics: There are several types of delay time characteristics available such as definite time delay and different types of inverse time delay characteristics. The selectivity between different overcurrent protections is normally enabled by co-ordination between the function time delays of the different protections. To enable optimal co-ordination between all overcurrent protections, they should have the same time delay characteristic. Therefore a wide range of standardized inverse time characteristics are available: IEC and ANSI.

The time characteristic for step 1 and 4 can be chosen as definite time delay or inverse time characteristic. Step 2 and 3 are always definite time delayed and are used in system where IDMT is not needed.

Power transformers can have a large inrush current, when being energized. This phenomenon is due to saturation of the transformer magnetic core during parts of the period. There is a risk that inrush current will reach levels above the pick-up current of the phase overcurrent protection. The inrush current has a large 2nd harmonic content. This can be used to avoid unwanted operation of the protection. Therefore, OC4PTOC (51/67) have a possibility of 2nd harmonic restrain if the level of this harmonic current reaches a value above a set percentage of the fundamental current.

8.1.3 Setting guidelines

The parameters for Four step phase overcurrent protection 3-phase output OC4PTOC (51/67) are set via the local HMI or PCM600.

The following settings can be done for OC4PTOC (51/67).

GlobalBaseSel: Selects the global base value group used by the function to define (*IBase*), (*VBase*) and (*SBase*).

MeasType: Selection of discrete Fourier filtered (*DFT*) or true RMS filtered (*RMS*) signals. *RMS* is used when the harmonic contents are to be considered, for example in applications with shunt capacitors.

Operation: The protection can be set to *Disabled* or *Enabled*

2ndHarmStab: Operate level of 2nd harmonic current restrain set in % of the fundamental current. The setting range is *5 - 100*% in steps of 1%. Default setting is 20%.

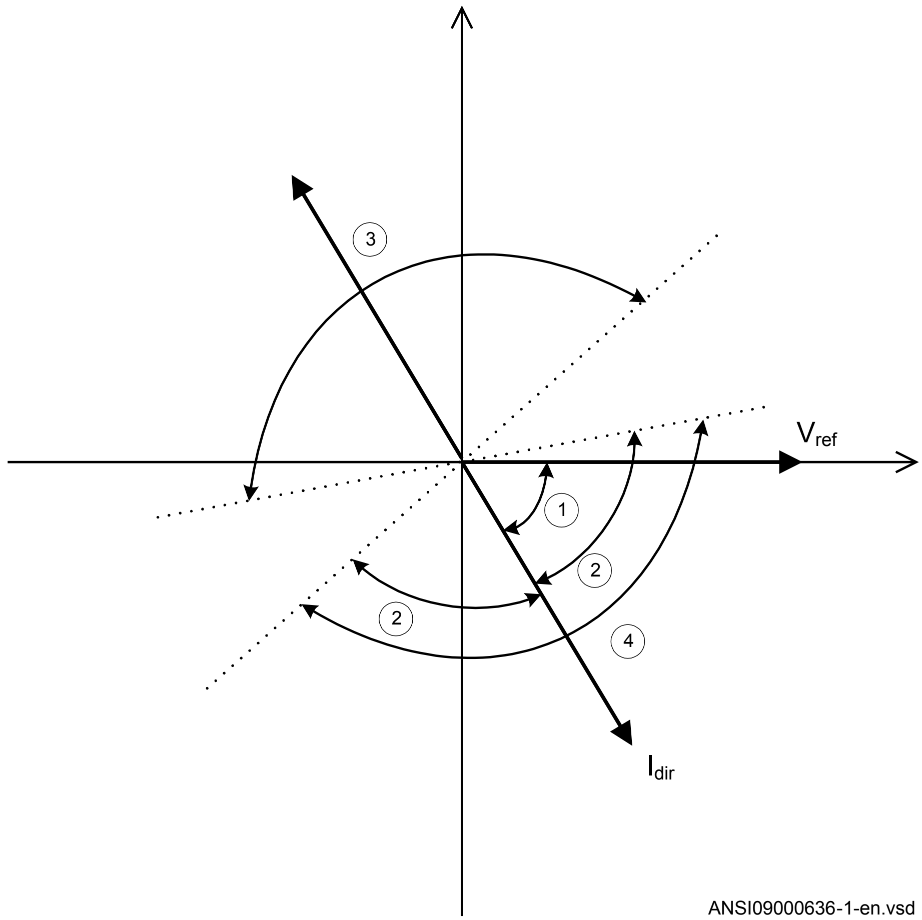


Figure 66: Directional function characteristic

1. RCA = Relay characteristic angle 55°
2. ROA = Relay operating angle 80°
3. Reverse
4. Forward

8.1.3.1 Settings for steps 1 to 4

n means step 1 and 4. *x* means step 1, 2, 3 and 4.

DirModeSelx: The directional mode of step *x*. Possible settings are *Disabled*/*Non-directional*/*Forward*/*Reverse*.

Characteristn: Selection of time characteristic for step *n*. Definite time delay and different types of inverse time characteristics are available according to table 21. Step 2 and 3 are always definite time delayed.

Table 21: Inverse time characteristics

Curve name
ANSI Extremely Inverse
ANSI Very Inverse
ANSI Normal Inverse
ANSI Moderately Inverse
ANSI/IEEE Definite time
ANSI Long Time Extremely Inverse
ANSI Long Time Very Inverse
ANSI Long Time Inverse
IEC Normal Inverse
IEC Very Inverse
IEC Inverse
IEC Extremely Inverse
IEC Short Time Inverse
IEC Long Time Inverse
IEC Definite Time
ASEA RI
RXIDG (logarithmic)

The different characteristics are described in Technical manual.

Pickupx: Operate phase current level for step *x* given in % of *IBase*.

tx: Definite time delay for step *x*. Used if definite time characteristic is chosen.

TDn: Time multiplier for inverse time delay for step *n*.

IMinn: Minimum operate current for step *n* in % of *IBase*. Set *IMinn* below *Pickupx* for every step to achieve ANSI reset characteristic according to standard. If *IMinn* is set above *Pickupx* for any step the ANSI reset works as if current is zero when current drops below *IMinn*.

tnMin: Minimum operate time for all inverse time characteristics. At high currents the inverse time characteristic might give a very short operation time. By setting this parameter the operation time of the step can never be shorter than the setting. Setting range: 0.000 - 60.000s in steps of 0.001s.

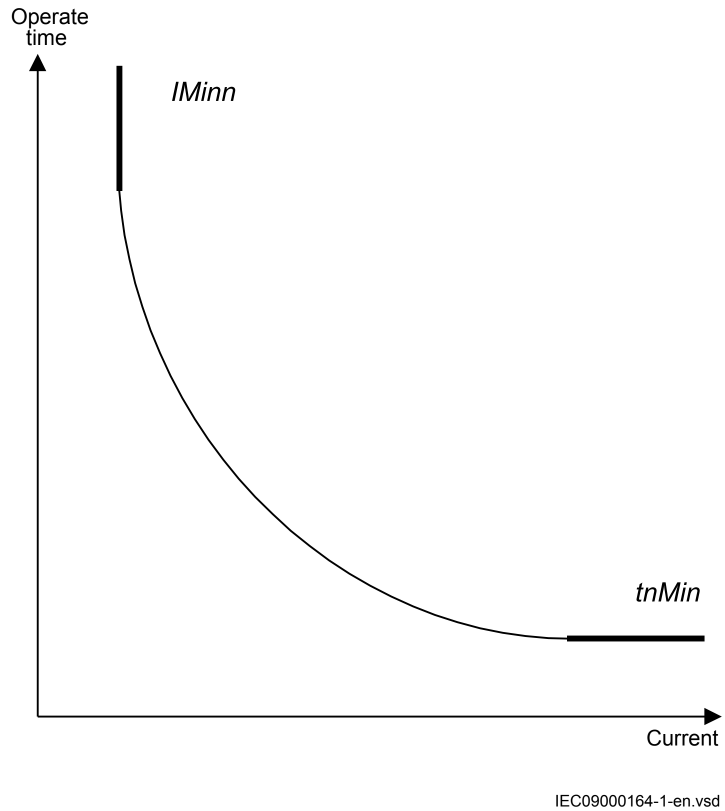


Figure 67: Minimum operate current and operation time for inverse time characteristics

In order to fully comply with curves definition setting parameter *tnMin* shall be set to the value, which is equal to the operating time of the selected inverse curve for measured current of twenty times the set current pickup value. Note that the operating time value is dependent on the selected setting value for time multiplier *TDn*.

HarmRestrainx: Enable block of step *n* from the harmonic restrain function (2nd harmonic). This function should be used when there is a risk if power transformer inrush currents might cause unwanted trip. Can be set *Disabled*/*Enabled*.

8.1.3.2 2nd harmonic restrain

If a power transformer is energized there is a risk that the transformer core will saturate during part of the period, resulting in an inrush transformer current. This will give a declining residual current in the network, as the inrush current is deviating between the phases. There is a risk that the phase overcurrent function will give an unwanted trip. The inrush current has a relatively large ratio of 2^{nd} harmonic component. This component can be used to create a restrain signal to prevent this unwanted function.

The settings for the 2nd harmonic restrain are described below.

2ndHarmStab: The rate of 2nd harmonic current content for activation of the 2nd harmonic restrain signal, to block chosen steps. The setting is given in % of the fundamental frequency residual current. The setting range is *5 - 100*% in steps of 1%. The default setting is 20% and can be used if a deeper investigation shows that no other value is needed..

HarmRestrainx: This parameter can be set *Disabled*/*Enabled*, to disable or enable the 2nd harmonic restrain.

The four step phase overcurrent protection 3-phase output can be used in different ways, depending on the application where the protection is used. A general description is given below.

The pickup current setting inverse time protection or the lowest current step constant inverse time protection must be given a current setting so that the highest possible load current does not cause protection operation. Here consideration also has to be taken to the protection reset current, so that a short peak of overcurrent does not cause operation of the protection even when the overcurrent has ceased. This phenomenon is described in figure 68.

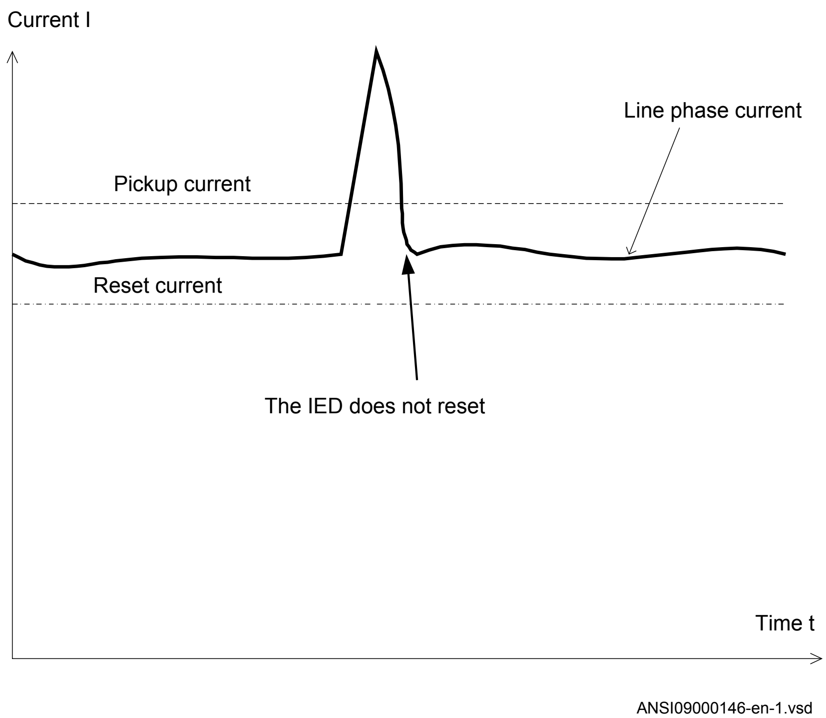


Figure 68: Pickup and reset current for an overcurrent protection

The lowest setting value can be written according to equation 26.

$$Ipu \geq 1.2 \cdot \frac{Imax}{k}$$

(Equation 26)

where:

1.2	is a safety factor,
k	is the resetting ratio of the protection
Imax	is the maximum load current.

The maximum load current on the line has to be estimated. There is also a demand that all faults, within the zone that the protection shall cover, must be detected by the phase overcurrent protection. The minimum fault current Iscmin, to be detected by the protection, must be calculated. Taking this value as a base, the highest pick up current setting can be written according to equation 27.

$$Ipu \leq 0.7 \cdot Iscmin$$

(Equation 27)

where:

0.7	is a safety factor
Iscmin	is the smallest fault current to be detected by the overcurrent protection.

As a summary the pickup current shall be chosen within the interval stated in equation 28.

$$1.2 \cdot \frac{Imax}{k} \leq Ipu \leq 0.7 \cdot Iscmin$$

(Equation 28)

The high current function of the overcurrent protection, which only has a short delay of the operation, must be given a current setting so that the protection is selective to other protection in the power system. It is desirable to have a rapid tripping of faults within as large portion as possible of the part of the power system to be protected by the protection (primary protected zone). A fault current calculation gives the largest current of faults, Iscmax, at the most remote part of the primary protected zone. Considerations have to be made to the risk of transient overreach, due to a possible DC component of the short circuit current. The lowest current setting of the most rapid stage, of the phase overcurrent protection, can be written according to

$$I_{high} \geq 1.2 \cdot k_t \cdot I_{sc\max}$$

(Equation 29)

where:

1.2	is a safety factor,
k_t	is a factor that takes care of the transient overreach due to the DC component of the fault current and can be considered to be less than 1.1
Iscmax	is the largest fault current at a fault at the most remote point of the primary protection zone.

The operate times of the phase overcurrent protection has to be chosen so that the fault time is so short that protected equipment will not be destroyed due to thermal overload, at the same time as selectivity is assured. For overcurrent protection, in a radial fed network, the time setting can be chosen in a graphical way. This is mostly used in the case of inverse time overcurrent protection. Figure 69 shows how the time-versus-current curves are plotted in a diagram. The time setting is chosen to get the shortest fault time with maintained selectivity. Selectivity is assured if the time difference between the curves is larger than a critical time difference.

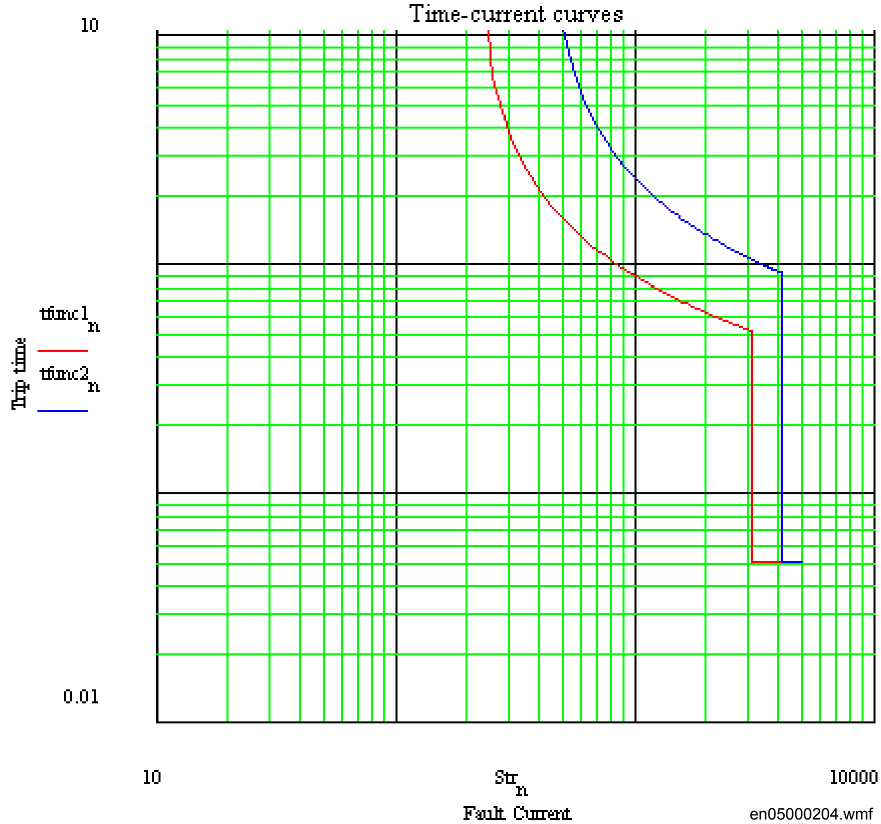


Figure 69: Fault time with maintained selectivity

To assure selectivity between different protections, in the radial network, there have to be a minimum time difference Δt between the time delays of two protections. The minimum time difference can be determined for different cases. To determine the shortest possible time difference, the operation time of protections, breaker opening time and protection resetting time must be known. These time delays can vary significantly between different protective equipment. The following time delays can be estimated:

Protection operation time:	15-60 ms
Protection resetting time:	15-60 ms
Breaker opening time:	20-120 ms

Example for time coordination

Assume two substations A and B directly connected to each other via one line, as shown in the figure 70. Consider a fault located at another line from the station B. The

fault current to the overcurrent protection of IED B1 has a magnitude so that the protection will have instantaneous function. The overcurrent protection of IED A1 must have a delayed function. The sequence of events during the fault can be described using a time axis, see figure 70.

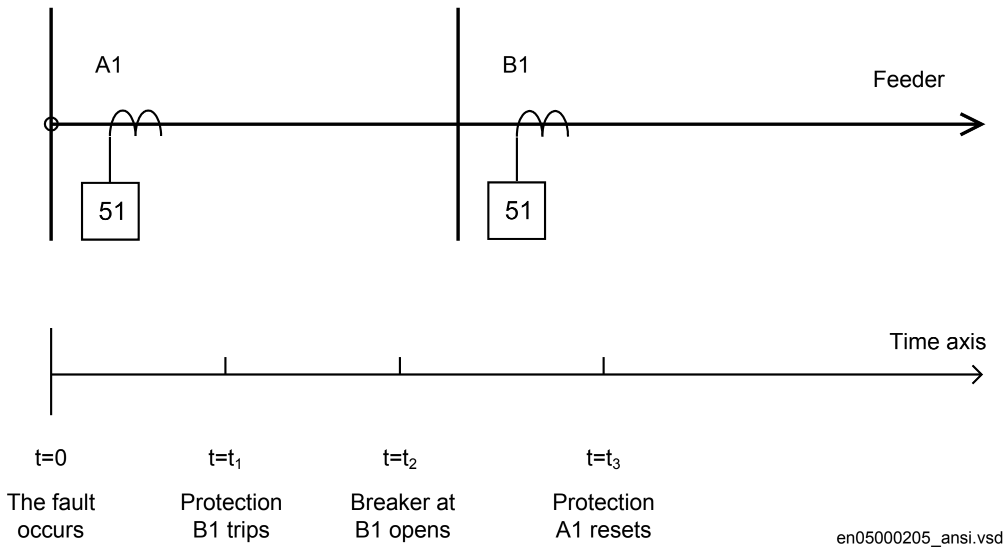


Figure 70: Sequence of events during fault

where:

$t=0$	is when the fault occurs,
$t=t_1$	is when the trip signal from the overcurrent protection at IED B1 is sent to the circuit breaker. The operation time of this protection is t_1,
$t=t_2$	is when the circuit breaker at IED B1 opens. The circuit breaker opening time is $t_2 - t_1$ and
$t=t_3$	is when the overcurrent protection at IED A1 resets. The protection resetting time is $t_3 - t_2$.

To ensure that the overcurrent protection at IED A1, is selective to the overcurrent protection at IED B1, the minimum time difference must be larger than the time t_3. There are uncertainties in the values of protection operation time, breaker opening time and protection resetting time. Therefore a safety margin has to be included. With normal values the needed time difference can be calculated according to equation 30.

$$\Delta t \geq 40\,ms + 100\,ms + 40\,ms + 40\,ms = 220\,ms$$

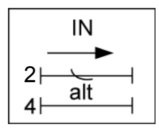
(Equation 30)

where it is considered that:

the operate time of overcurrent protection B1	is 40 ms
the breaker open time	is 100 ms
the resetting time of protection A1	is 40 ms and
the additional margin	is 40 ms

8.2 Four step residual overcurrent protection, zero, negative sequence direction EF4PTOC (51N/67N)

8.2.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Four step residual overcurrent protection, zero or negative sequence direction	EF4PTOC		51N/67N

8.2.2 Application

The four step residual overcurrent protection, zero or negative sequence direction EF4PTOC (51N_67N) is used in several applications in the power system. Some applications are:

- Ground-fault protection of feeders in effectively grounded distribution systems. Normally these feeders have radial structure.
- Back-up ground-fault protection of subtransmission and transmission lines.
- Sensitive ground-fault protection of transmission lines. EF4PTOC (51N_67N) can have better sensitivity to detect resistive phase-to-ground-faults compared to distance protection.
- Back-up ground-fault protection of power transformers with ground source at substation.

- Ground-fault protection of different kinds of equipment connected to the power system such as shunt capacitor banks, shunt reactors and others.
- Negative sequence direcitonal ground-fault protection of feeders with PTs connected in Open Delta connection from which it is not possible to derive Zero sequence voltage.
- Negative sequence directional ground-fault protection of double-circuit medium or long transmission lines with significant mutual coupling.

In many applications several steps with different current pickup levels and time delays are needed. EF4PTOC (51N_67N) can have up to four, individual settable steps. The flexibility of each step of EF4PTOC (51N_67N) is great. The following options are possible:

Non-directional/Directional function: In some applications the non-directional functionality is used. This is mostly the case when no fault current can be fed from the protected object itself. In order to achieve both selectivity and fast fault clearance, the directional function can be necessary. This can be the case for ground-fault protection in meshed and effectively grounded transmission systems. The directional residual overcurrent protection is also well suited to operate in teleprotection communication schemes, which enables fast clearance of ground faults on transmission lines. The directional function uses the polarizing quantity as decided by setting. Voltage polarizing ($3V_0$ or V_2) is most commonly used, but alternatively current polarizing ($3I_0$ or I_2) where currents in transformer neutrals providing the neutral (zero sequence) source (ZN) is used to polarize (IPol · ZN) the function. Dual polarizing where the sum of both voltage and current components is allowed to polarize can also be selected.

Choice of time characteristics: There are several types of time characteristics available such as definite time delay and different types of inverse time characteristics. The selectivity between different overcurrent protections is normally enabled by co-ordination between the operate time of the different protections. To enable optimal co-ordination all overcurrent protections, to be co-ordinated against each other, should have the same time characteristic. Therefore a wide range of standardized inverse time characteristics are available: IEC and ANSI. The time characteristic for step 1 and 4 can be chosen as definite time delay or inverse time characteristic. Step 2 and 3 are always definite time delayed and are used in system where IDMT is not needed.

Table 22: Time characteristics

Curve name
ANSI Extremely Inverse
ANSI Very Inverse
ANSI Normal Inverse
ANSI Moderately Inverse
Table continues on next page

Curve name
ANSI/IEEE Definite time
ANSI Long Time Extremely Inverse
ANSI Long Time Very Inverse
ANSI Long Time Inverse
IEC Normal Inverse
IEC Very Inverse
IEC Inverse
IEC Extremely Inverse
IEC Short Time Inverse
IEC Long Time Inverse
IEC Definite Time
ASEA RI
RXIDG (logarithmic)

Power transformers can have a large inrush current, when being energized. This inrush current can have residual current components. The phenomenon is due to saturation of the transformer magnetic core during parts of the cycle. There is a risk that inrush current will give a residual current that reaches level above the pickup current of the residual overcurrent protection. The inrush current has a large second harmonic content. This can be used to avoid unwanted operation of the protection. Therefore, EF4PTOC (51N_67N) has a possibility of second harmonic restrain *2ndHarmStab* if the level of this harmonic current reaches a value above a set percentage of the fundamental current.

8.2.3 Setting guidelines

The parameters for the four step residual overcurrent protection, zero or negative sequence direction EF4PTOC (51N/67N) are set via the local HMI or PCM600.

The following settings can be done for the four step residual overcurrent protection.

GlobalBaseSel: Selects the global base value group used by the function to define (*IBase*), (*VBase*) and (*SBase*).

Operation: Sets the protection to *Enabled* or *Disabled*.

EnaDir: Enables the directional calculation in addition to the directional mode selection in each step.

8.2.3.1 Settings for steps 1 and 4

n means step 1 and 4. *x* means step 1, 2, 3 and 4.

DirModeSelx: The directional mode of step *x*. Possible settings are *Disabled*/*Non-directional*/*Forward*/*Reverse*.

Characteristx: Selection of time characteristic for step *x*. Definite time delay and different types of inverse time characteristics are available.

Inverse time characteristic enables fast fault clearance of high current faults at the same time as selectivity to other inverse time phase overcurrent protections can be assured. This is mainly used in radial fed networks but can also be used in meshed networks. In meshed networks the settings must be based on network fault calculations.

To assure selectivity between different protections, in the radial network, there have to be a minimum time difference Δt between the time delays of two protections. The minimum time difference can be determined for different cases. To determine the shortest possible time difference, the operation time of protections, breaker opening time and protection resetting time must be known. These time delays can vary significantly between different protective equipment. The following time delays can be estimated:

Protection operate time:	15-60 ms
Protection resetting time:	15-60 ms
Breaker opening time:	20-120 ms

The different characteristics are described in the Technical Manual (TM).

Pickup"x": Operate residual current level for step *x* given in % of *IBase*.

TDn: Time multiplier for the dependent (inverse) characteristic for step *n*.

IMinn: Minimum operate current for step *n* in % of *IBase*. Set *IMinn* below *Pickupx* for every step to achieve ANSI reset characteristic according to standard. If *IMinn* is set above *Pickupx* for any step the ANSI reset works as if current is zero when current drops below *IMinn*.

tnMin: Minimum operating time for inverse time characteristics. At high currents the inverse time characteristic might give a very short operation time. By setting this parameter the operation time of the step *n* can never be shorter than the setting.

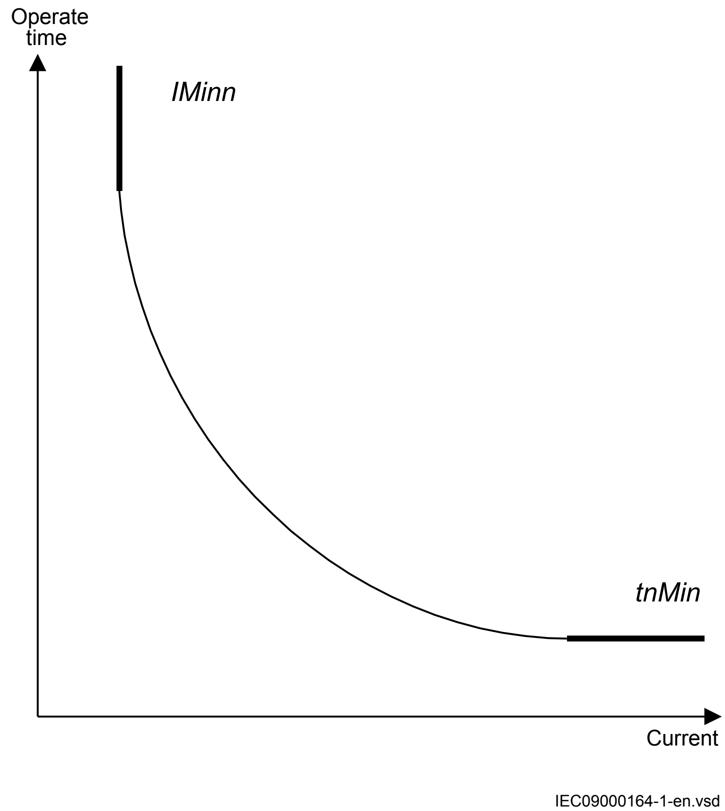


Figure 71: Minimum operate current and operate time for inverse time characteristics

In order to fully comply with curves definition the setting parameter *txMin* shall be set to the value which is equal to the operate time of the selected IEC inverse curve for measured current of twenty times the set current pickup value. Note that the operate time value is dependent on the selected setting value for time multiplier *TDn*.

8.2.3.2 Common settings for all steps

tx: Definite time delay for step *x*. Used if definite time characteristic is chosen.

AngleRCA: Relay characteristic angle given in degree. This angle is defined as shown in figure 72. The angle is defined positive when the residual current lags the reference voltage (Vpol = $3V_0$ or V_2)

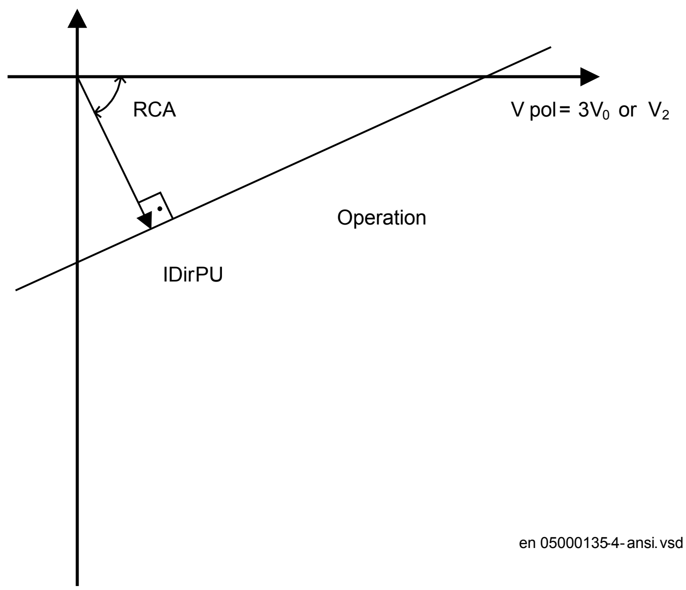


Figure 72: Relay characteristic angle given in degree

In a normal transmission network a normal value of RCA is about 65°. The setting range is -180° to +180°.

polMethod: Defines if the directional polarization is from

- *Voltage* ($3V_0$ or V_2)
- *Current* ($3I_0 \cdot$ ZNpol or $3I_2 \cdot$ZNpol where ZNpol is RNpol + jXNpol), or
- both currents and voltage, *Dual* (dual polarizing, ($3V_0 + 3I_0 \cdot$ ZNpol) or ($V_2 + I_2 \cdot$ ZNpol)).

Normally voltage polarizing from the internally calculated residual sum or an external open delta is used.

Current polarizing is useful when the local source is strong and a high sensitivity is required. In such cases the polarizing voltage ($3V_0$) can be below 1% and it is then necessary to use current polarizing or dual polarizing. Multiply the required set current (primary) with the minimum impedance (ZNpol) and check that the percentage of the phase-to-ground voltage is definitely higher than 1% (minimum $3V_0$>*VPolMin* setting) as a verification.

RNPol, XNPol: The zero-sequence source is set in primary ohms as base for the current polarizing. The polarizing voltage is then achieved as $3I_0 \cdot$ ZNpol. The ZNpol can be defined as (ZS_1-ZS_0)/3, that is the ground return impedance of the source behind the

protection. The maximum ground-fault current at the local source can be used to calculate the value of ZN as $V/(\sqrt{3} \cdot 3I_0)$ Typically, the minimum ZNPol (3 · zero sequence source) is set. Setting is in primary ohms.

When the dual polarizing method is used it is important that the product *INx>*· ZNpol is not greater than $3V_0$. If so, there is a risk for incorrect operation for faults in the reverse direction.

IPolMin: is the minimum ground-fault current accepted for directional evaluation. For smaller currents than this value the operation will be blocked. Typical setting is 5-10% of *IBase*.

VPolMin: Minimum polarization (reference) residual voltage for the directional function, given in % of *VBase*/√3.

IDirPU: Operate residual current release level in % of *IBase* for directional comparison scheme. The setting is given in % of *IBase* and must be set below the lowest *INx>* setting, set for the directional measurement. The output signals, PUFW and PUREV can be used in a teleprotection scheme. The appropriate signal should be configured to the communication scheme block.

8.2.3.3 2nd harmonic restrain

If a power transformer is energized there is a risk that the current transformer core will saturate during part of the period, resulting in a transformer inrush current. This will give a declining residual current in the network, as the inrush current is deviating between the phases. There is a risk that the residual overcurrent function will give an unwanted trip. The inrush current has a relatively large ratio of 2nd harmonic component. This component can be used to create a restrain signal to prevent this unwanted function.

At current transformer saturation a false residual current can be measured by the protection. Also here the 2^{nd} harmonic restrain can prevent unwanted operation.

2ndHarmStab: The rate of 2nd harmonic current content for activation of the 2nd harmonic restrain signal. The setting is given in % of the fundamental frequency residual current.

HarmRestrainx: Enable block of step *x* from the harmonic restrain function.

8.3 Sensitive directional residual overcurrent and power protection SDEPSDE (67N)

8.3.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Sensitive directional residual over current and power protection	SDEPSDE	-	67N

8.3.2 Application

In networks with high impedance grounding, the phase-to-ground fault current is significantly smaller than the short circuit currents. Another difficulty for ground-fault protection is that the magnitude of the phase-to-ground fault current is almost independent of the fault location in the network.

Directional residual current can be used to detect and give selective trip of phase-to-ground faults in high impedance grounded networks. The protection uses the residual current component $3I_0 \cdot \cos \varphi$, where φ is the angle between the residual current and the residual voltage ($-3V_0$), compensated with a characteristic angle. Alternatively, the function can be set to strict $3I_0$ level with an check of angle $3I_0$ and $\cos \varphi$.

Directional residual power can also be used to detect and give selective trip of phase-to-ground faults in high impedance grounded networks. The protection uses the residual power component $3I_0 \cdot 3V_0 \cdot \cos \varphi$, where φ is the angle between the residual current and the reference residual voltage, compensated with a characteristic angle.

A normal non-directional residual current function can also be used with definite or inverse time delay.

A back-up neutral point voltage function is also available for non-directional sensitive back-up protection.

In an isolated network, that is, the network is only coupled to ground via the capacitances between the phase conductors and ground, the residual current always has -90º phase shift compared to the reference residual voltage. The characteristic angle is chosen to -90º in such a network.

In resistance grounded networks or in Petersen coil grounded, with a parallel resistor, the active residual current component (in phase with the residual voltage) should be used for the ground-fault detection. In such networks the characteristic angle is chosen to 0º.

As the magnitude of the residual current is independent of the fault location the selectivity of the ground-fault protection is achieved by time selectivity.

When should the sensitive directional residual overcurrent protection be used and when should the sensitive directional residual power protection be used? Consider the following facts:

- Sensitive directional residual overcurrent protection gives possibility for better sensitivity
- Sensitive directional residual power protection gives possibility to use inverse time characteristics. This is applicable in large high impedance grounded networks, with large capacitive ground-fault current
- In some power systems a medium size neutral point resistor is used, for example, in low impedance grounded system. Such a resistor will give a resistive ground-fault current component of about 200 - 400 A at a zero resistive phase-to-ground fault. In such a system the directional residual power protection gives better possibilities for selectivity enabled by inverse time power characteristics.

8.3.3 Setting guidelines

The sensitive ground-fault protection is intended to be used in high impedance grounded systems, or in systems with resistive grounding where the neutral point resistor gives an ground-fault current larger than what normal high impedance gives but smaller than the phase to phase short circuit current.

In a high impedance system the fault current is assumed to be limited by the system zero sequence shunt impedance to ground and the fault resistance only. All the series impedances in the system are assumed to be zero.

In the setting of ground-fault protection, in a high impedance grounded system, the neutral point voltage (zero sequence voltage) and the ground-fault current will be calculated at the desired sensitivity (fault resistance). The complex neutral point voltage (zero sequence) can be calculated as:

$$V_0 = \frac{V_{phase}}{1 + \frac{3 \cdot R_f}{Z_0}}$$

(Equation 31)

Where

V_{phase} is the phase voltage in the fault point before the fault,

R_f is the resistance to ground in the fault point and

Z_0 is the system zero sequence impedance to ground

The fault current, in the fault point, can be calculated as:

$$I_j = 3I_0 = \frac{3 \cdot V_{phase}}{Z_0 + 3 \cdot R_f}$$

(Equation 32)

The impedance Z_0 is dependent on the system grounding. In an isolated system (without neutral point apparatus) the impedance is equal to the capacitive coupling between the phase conductors and ground:

$$Z_0 = -jX_c = -j\frac{3 \cdot V_{phase}}{I_j}$$

(Equation 33)

Where

I_j	is the capacitive ground-fault current at a non-resistive phase to ground-fault
X_c	is the capacitive reactance to ground

In a system with a neutral point resistor (resistance grounded system) the impedance Z_0 can be calculated as:

$$Z_0 = \frac{-jX_c \cdot 3R_n}{-jX_c + 3R_n}$$

(Equation 34)

Where

R_n	is the resistance of the neutral point resistor

In many systems there is also a neutral point reactor (Petersen coil) connected to one or more transformer neutral points. In such a system the impedance Z_0 can be calculated as:

$$Z_0 = -jX_c \,//\, 3R_n \,//\, j3X_n = \frac{9R_n X_n X_c}{3X_n X_c + j3R_n \cdot (3X_n - X_c)}$$

(Equation 35)

Where

X_n is the reactance of the Petersen coil. If the Petersen coil is well tuned we have $3X_n = X_c$ In this case the impedance Z_0 will be: $Z_0 = 3R_n$

Now consider a system with an grounding via a resistor giving higher ground-fault current than the high impedance grounding. The series impedances in the system can no longer be neglected. The system with a single phase to ground-fault can be described as in figure 73.

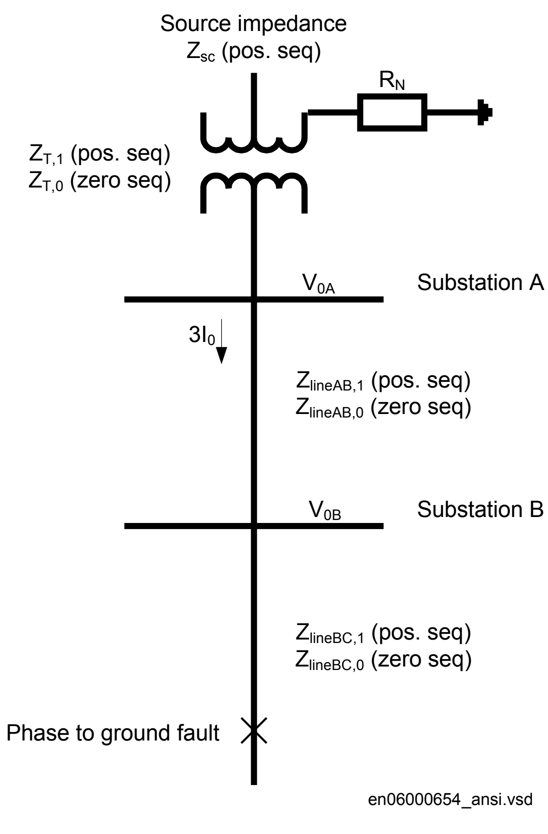


Figure 73: Equivalent of power system for calculation of setting

The residual fault current can be written:

$$3I_0 = \frac{3V_{phase}}{2 \cdot Z_1 + Z_0 + 3 \cdot R_f}$$

(Equation 36)

Where

V_{phase}	is the phase voltage in the fault point before the fault
Z_1	is the total positive sequence impedance to the fault point. $Z_1 = Z_{sc}+Z_{T,1}+Z_{lineAB,1}+Z_{lineBC,1}$
Z_0	is the total zero sequence impedance to the fault point. $Z_0 = Z_{T,0}+3R_N+Z_{lineAB,0}+Z_{lineBC,0}$
R_f	is the fault resistance.

The residual voltages in stations A and B can be written:

$$V_{0A} = 3I_0 \cdot (Z_{T,0} + 3R_N)$$

(Equation 37)

$$V_{OB} = 3I_0 \cdot (Z_{T,0} + 3R_N + Z_{lineAB,0})$$

(Equation 38)

The residual power, measured by the sensitive ground-fault protections in A and B will be:

$$S_{0A} = 3V_{0A} \cdot 3I_0$$

(Equation 39)

$$S_{0B} = 3V_{0B} \cdot 3I_0$$

(Equation 40)

The residual power is a complex quantity. The protection will have a maximum sensitivity in the characteristic angle RCA. The apparent residual power component in the characteristic angle, measured by the protection, can be written:

$$S_{0A,prot} = 3V_{0A} \cdot 3I_0 \cdot \cos\varphi_A$$

(Equation 41)

$$S_{0B,prot} = 3V_{0B} \cdot 3I_0 \cdot \cos\varphi_B$$

(Equation 42)

The angles φ_A and φ_B are the phase angles between the residual current and the residual voltage in the station compensated with the characteristic angle RCA.

The protection will use the power components in the characteristic angle direction for measurement, and as base for the inverse time delay.

The inverse time delay is defined as:

$$t_{inv} = \frac{TDSN \cdot (3I_0 \cdot 3V_0 \cdot \cos\phi(\text{reference}))}{3I_0 \cdot 3V_0 \cos\phi(\text{measured})}$$

(Equation 43)

GlobalBaseSel: Selects the global base value group used by the function to define (*IBase*), (*VBase*) and (*SBase*).

The function can be set *Enabled/Disabled* with the setting of *Operation*.

With the setting *OpModeSel* the principle of directional function is chosen.

With *OpModeSel* set to *3I0cosfi* the current component in the direction equal to the characteristic angle*RCADir* has the maximum sensitivity. The characteristic for *RCADir* is equal to 0° is shown in figure 74.

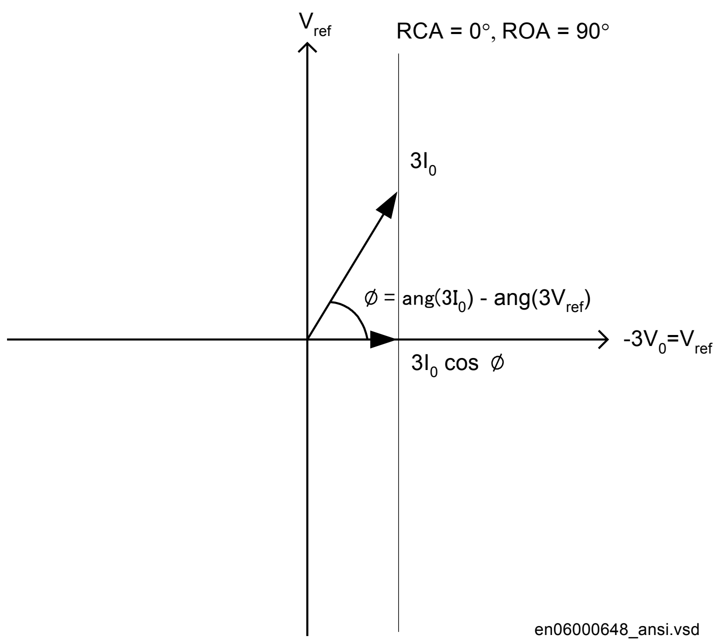


Figure 74: Characteristic for RCADir equal to 0°

The characteristic is for *RCADir* equal to -90° is shown in figure 75.

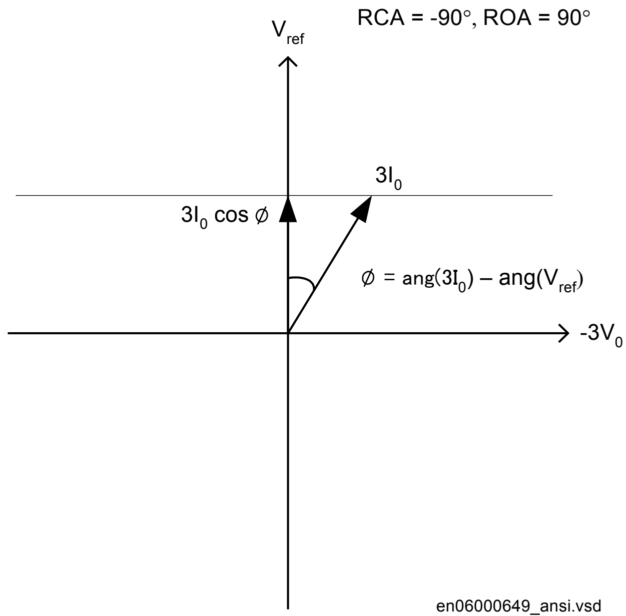


Figure 75: Characteristic for RCADir equal to -90°

When *OpModeSel* is set to *3I03V0Cosfi* the apparent residual power component in the direction is measured.

When *OpModeSel* is set to *3I0 and fi* the function will operate if the residual current is larger than the setting *INDirPU* and the residual current angle is within the sector *RCADir* ± *ROADir*.

The characteristic for *RCADir* = 0° and *ROADir* = 80° is shown in figure 76.

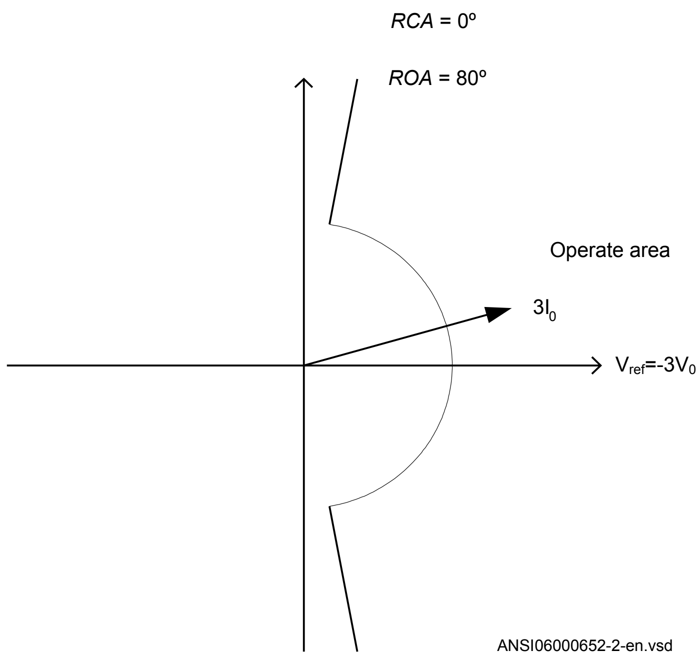


Figure 76: Characteristic for RCADir = 0° and ROADir = 80°

DirMode is set *Forward* or *Reverse* to set the direction of the trip function from the directional residual current function.

All the directional protection modes have a residual current release level setting *INRelPU* which is set in % of *IBase*. This setting should be chosen smaller than or equal to the lowest fault current to be detected.

All the directional protection modes have a residual voltage release level setting *VNRelPU* which is set in % of *VBase*. This setting should be chosen smaller than or equal to the lowest fault residual voltage to be detected.

tDef is the definite time delay, given in s, for the directional residual current protection if definite time delay is chosen.

The characteristic angle of the directional functions *RCADir* is set in degrees. *RCADir* is normally set equal to 0° in a high impedance grounded network with a neutral point resistor as the active current component is appearing out on the faulted feeder only. *RCADir* is set equal to -90° in an isolated network as all currents are mainly capacitive.

The relay open angle *ROADir* is set in degrees. For angles differing more than *ROADir* from*RCADir* the function from the protection is blocked. The setting can be used to prevent unwanted function for non-faulted feeders, with large capacitive ground-fault current contributions, due to CT phase angle error.

INCosPhiPU is the operate current level for the directional function when *OpModeSel* is set *3I0Cosfi*. The setting is given in % of *IBase*. The setting should be based on calculation of the active or capacitive ground-fault current at required sensitivity of the protection.

SN_PU is the operate power level for the directional function when *OpModeSel* is set *3I03V0Cosfi*. The setting is given in % of *SBase*. The setting should be based on calculation of the active or capacitive ground-fault residual power at required sensitivity of the protection.

The input transformer for the Sensitive directional residual over current and power protection function has the same short circuit capacity as the phase current transformers.

If the time delay for residual power is chosen the delay time is dependent on two setting parameters. *SRef* is the reference residual power, given in % of *SBase*. *TDSN* is the time multiplier. The time delay will follow the following expression:

$$t_{inv} = \frac{TDSN \cdot Sref}{3I_0 \cdot 3V_0 \cdot \cos\varphi(measured)}$$

(Equation 44)

INDirPU is the operate current level for the directional function when *OpModeSel* is set *3I0 and fi*. The setting is given in % of *IBase*. The setting should be based on calculation of the ground-fault current at required sensitivity of the protection.

OpINNonDir is set *Enabled* to activate the non-directional residual current protection.

INNonDirPU is the operate current level for the non-directional function. The setting is given in % of *IBase*. This function can be used for detection and clearance of cross-country faults in a shorter time than for the directional function. The current setting should be larger than the maximum single-phase residual current out on the protected line.

TimeChar is the selection of time delay characteristic for the non-directional residual current protection. Definite time delay and different types of inverse time characteristics are available:

ANSI Extremely Inverse
ANSI Very Inverse
ANSI Normal Inverse
ANSI Moderately Inverse
ANSI/IEEE Definite time
ANSI Long Time Extremely Inverse
ANSI Long Time Very Inverse
Table continues on next page

ANSI Long Time Inverse
IEC Normal Inverse
IEC Very Inverse
IEC Inverse
IEC Extremely Inverse
IEC Short Time Inverse
IEC Long Time Inverse
IEC Definite time
ASEA RI
RXIDG (logarithmic)

The different characteristics are described in Technical Manual.

tINNonDir is the definite time delay for the non directional ground-fault current protection, given in s.

OpVN is set *Enabled* to activate the trip function of the residual voltage protection.

tVN is the definite time delay for the trip function of the residual voltage protection, given in s.

8.4 Thermal overload protection, two time constants TRPTTR (49)

8.4.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Thermal overload protection, two time constants	TRPTTR		49

8.4.2 Application

Transformers in the power system are designed for a certain maximum load current (power) level. If the current exceeds this level the losses will be higher than expected.

As a consequence the temperature of the transformer will increase. If the temperature of the transformer reaches too high values the equipment might be damaged:

- The insulation within the transformer will experience forced ageing. As a consequence of this, the risk of internal phase-to-phase or phase-to-ground faults will increase.
- There might be hot spots within the transformer, which will degrade the paper insulation. It might also cause bubbling in the transformer oil.

In stressed situations in the power system it can be required to overload transformers for a limited time. This should be done without the above mentioned risks. The thermal overload protection provides information and makes temporary overloading of transformers possible.

The permissible load level of a power transformer is highly dependent on the cooling system of the transformer. There are two main principles:

- OA: The air is naturally circulated to the coolers without fans and the oil is naturally circulated without pumps.
- FOA: The coolers have fans to force air for cooling and pumps to force the circulation of the transformer oil.

The protection can have two sets of parameters, one for non-forced cooling and one for forced cooling. Both the permissive steady state loading level as well as the thermal time constant is influenced by the cooling system of the transformer. The two parameters sets can be activated by the binary input signal COOLING. This can be used for transformers where forced cooling can be taken out of operation, for example at fan or pump faults.

The thermal overload protection estimates the internal heat content of the transformer (temperature) continuously. This estimation is made by using a thermal model of the transformer, which is based on current measurement.

If the heat content of the protected transformer reaches a set alarm level a signal can be given to the operator. Two alarm levels are available. This enables preventive actions in the power system to be taken before dangerous temperatures are reached. If the temperature continues to increase to the trip value, the protection initiates a trip of the protected transformer.

After tripping by the thermal overload protection, the transformer will cool down over time. There will be a time gap before the heat content (temperature) reaches such a level so that the transformer can be taken into service again. Therefore, the function will continue to estimate the heat content using a set cooling time constant. Energizing of the transformer can be blocked until the heat content has reached a set level.

8.4.3 Setting guideline

The parameters for the thermal overload protection, two time constants (TRPTTR, 49) are set via the local HMI or through the Protection and Control Manager (PCM600).

The following settings can be done for the thermal overload protection:

GlobalBaseSel: Selects the global base value group used by the function to define (*IBase*), (*VBase*) and (*SBase*).

Operation: Sets the mode of operation. *Disabled* switches off the complete function.

IRef: Reference level of the current given in % of *IBase*. When the current is equal to *IRef* the final (steady state) heat content is equal to 1. It is suggested to give a setting corresponding to the rated current of the transformer winding. Transformer rated current / *IBase** 100%.

IBase1: Base current for setting given as percentage of *IBase*. This setting shall be related to the status with no COOLING input. It is suggested to give a setting corresponding to the rated current of the transformer with natural cooling (OA).

IBase2: Base current for setting given as percentage of *IBase*. This setting shall be related to the status with activated COOLING input. It is suggested to give a setting corresponding to the rated current of the transformer with forced cooling (FOA). If the transformer has no forced cooling *IBase2* can be set equal to *IBase1*.

Tau1: The thermal time constant of the protected transformer, related to *IBase1* (no cooling) given in minutes.

Tau2: The thermal time constant of the protected transformer, related to *IBase2* (with cooling) given in minutes.

The thermal time constant should be obtained from the transformer manufacturers manuals. The thermal time constant is dependent on the cooling and the amount of oil. Normal time constants for medium and large transformers (according to IEC 60076-7) are about 2.5 hours for naturally cooled transformers and 1.5 hours for forced cooled transformers.

The time constant can be estimated from measurements of the oil temperature during a cooling sequence (described in IEC 60076-7). It is assumed that the transformer is operated at a certain load level with a constant oil temperature (steady state operation). The oil temperature above the ambient temperature is $\Delta\Theta_{o0}$. Then the transformer is disconnected from the grid (no load). After a time t of at least 30 minutes the temperature of the oil is measured again. Now the oil temperature above the ambient temperature is $\Delta\Theta_{ot}$. The thermal time constant can now be estimated as:

$$\tau = \frac{t}{\ln \Delta\Theta_{o0} - \ln \Delta\Theta_{ot}}$$

(Equation 45)

If the transformer has forced cooling (FOA) the measurement should be made both with and without the forced cooling in operation, giving *Tau2* and *Tau1*.

The time constants can be changed if the current is higher than a set value or lower than a set value. If the current is high it is assumed that the forced cooling is activated while it is deactivated at low current. The setting of the parameters below enables automatic adjustment of the time constant.

Tau1High: Multiplication factor to adjust the time constant *Tau1* if the current is higher than the set value *IHighTau1*. *IHighTau1* is set in % of *IBase1*.

Tau1Low: Multiplication factor to adjust the time constant *Tau1* if the current is lower than the set value *ILowTau1*. *ILowTau1* is set in % of *IBase1*.

Tau2High: Multiplication factor to adjust the time constant *Tau2* if the current is higher than the set value *IHighTau2*. *IHighTau2* is set in % of *IBase2*.

Tau2Low: Multiplication factor to adjust the time constant *Tau2* if the current is lower than the set value *ILowTau2*. *ILowTau2* is set in % of *IBase2*.

The possibility to change time constant with the current value as the base can be useful in different applications. Below some examples are given:

- In case a total interruption (low current) of the protected transformer all cooling possibilities will be inactive. This can result in a changed value of the time constant.
- If other components (motors) are included in the thermal protection, there is a risk of overheating of that equipment in case of very high current. The thermal time constant is often smaller for a motor than for the transformer.

ITrip: The steady state current that the transformer can withstand. The setting is given in % of *IBase1* or *IBase2*.

Alarm1: Heat content level for activation of the signal ALARM1. ALARM1 is set in % of the trip heat content level.

Alarm2: Heat content level for activation of the output signal ALARM2. ALARM2 is set in % of the trip heat content level.

LockoutReset: Lockout release level of heat content to release the lockout signal. When the thermal overload protection trips a lock-out signal is activated. This signal is intended to block switching on of the protected circuit transformer as long as the transformer temperature is high. The signal is released when the estimated heat content

is below the set value. This temperature value should be chosen below the alarm temperature. *LockoutReset* is set in % of the trip heat content level.

Warning: If the calculated time to trip factor is below the setting *Warning* a warning signal is activated. The setting is given in minutes.

8.5 Breaker failure protection 3-phase activation and output CCRBRF (50BF)

8.5.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Breaker failure protection, 3-phase activation and output	CCRBRF	3I>BF	50BF

8.5.2 Application

In the design of the fault clearance system the N-1 criterion is often used. This means that a fault needs to be cleared even if any component in the fault clearance system is faulty. One necessary component in the fault clearance system is the circuit breaker. It is from practical and economical reason not feasible to duplicate the circuit breaker for the protected component. Instead a breaker failure protection is used.

Breaker failure protection, 3-phase activation and output (CCRBRF, 50BF) will issue a back-up trip command to adjacent circuit breakers in case of failure to trip of the “normal” circuit breaker for the protected component. The detection of failure to break the current through the breaker is made by means of current measurement or as detection of remaining trip signal (unconditional).

CCRBRF (50BF) can also give a re-trip. This means that a second trip signal is sent to the protected circuit breaker. The re-trip function can be used to increase the probability of operation of the breaker, or it can be used to avoid back-up trip of many breakers in case of mistakes during relay maintenance and test.

8.5.3 Setting guidelines

The parameters for Breaker failure protection 3-phase activation and output CCRBRF (50BF) are set via the local HMI or PCM600.

The following settings can be done for the breaker failure protection.

GlobalBaseSel: Selects the global base value group used by the function to define (*IBase*), (*VBase*) and (*SBase*).

Operation: *Disabled*/*Enabled*

FunctionMode This parameter can be set *Current* or *Contact*. This states the way the detection of failure of the breaker is performed. In the mode current the current measurement is used for the detection. In the mode *Contact* the long duration of breaker position signal is used as indicator of failure of the breaker. The mode *Current&Contact* means that both ways of detections are activated. *Contact* mode can be usable in applications where the fault current through the circuit breaker is small. This can be the case for some generator protection application (for example reverse power protection) or in case of line ends with weak end infeed.

RetripMode: This setting states how the re-trip function shall operate. *Retrip Off* means that the re-trip function is not activated. *CB Pos Check* (circuit breaker position check) and *Current* means that a phase current must be larger than the operate level to allow re-trip. *CB Pos Check* (circuit breaker position check) and *Contact* means re-trip is done when circuit breaker is closed (breaker position is used). *No CBPos Check* means re-trip is done without check of breaker position.

Table 23: Dependencies between parameters RetripMode and FunctionMode

RetripMode	*FunctionMode*	Description
Retrip Off	N/A	the re-trip function is not activated
CB Pos Check	*Current*	a phase current must be larger than the operate level to allow re-trip
	Contact	re-trip is done when breaker position indicates that breaker is still closed after re-trip time has elapsed
	Current&Contact	both methods are used
No CBPos Check	*Current*	re-trip is done without check of breaker position
	Contact	re-trip is done without check of breaker position
	Current&Contact	both methods are used

BuTripMode: Back-up trip mode is given to state sufficient current criteria to detect failure to break. For *Current* operation *2 out of 4* means that at least two currents, of the three-phase currents and the residual current, shall be high to indicate breaker failure. *1 out of 3* means that at least one current of the three-phase currents shall be high to indicate breaker failure. *1 out of 4* means that at least one current of the three-phase currents or the residual current shall be high to indicate breaker failure. In most applications *1 out of 3* is sufficient. For *Contact* operation means back-up trip is done when circuit breaker is closed (breaker position is used).

Pickup_PH: Current level for detection of breaker failure, set in % of *IBase*. This parameter should be set so that faults with small fault current can be detected. The setting can be chosen in accordance with the most sensitive protection function to start the breaker failure protection. Typical setting is 10% of *IBase*.

Pickup_BlkCont: If any contact based detection of breaker failure is used this function can be blocked if any phase current is larger than this setting level. If the *FunctionMode* is set *Current&Contact* breaker failure for high current faults are safely detected by the current measurement function. To increase security the contact based function should be disabled for high currents. The setting can be given within the range 5 – 200% of *IBase*.

Pickup_N: Residual current level for detection of breaker failure set in % of *IBase*. In high impedance grounded systems the residual current at phase- to-ground faults are normally much smaller than the short circuit currents. In order to detect breaker failure at single-phase-ground faults in these systems it is necessary to measure the residual current separately. Also in effectively grounded systems the setting of the ground-fault current protection can be chosen to relatively low current level. The *BuTripMode* is set *1 out of 4*. The current setting should be chosen in accordance to the setting of the sensitive ground-fault protection. The setting can be given within the range 2 – 200 % of *IBase*.

t1: Time delay of the re-trip. The setting can be given within the range 0 – 60s in steps of 0.001 s. Typical setting is 0 – 50ms.

t2: Time delay of the back-up trip. The choice of this setting is made as short as possible at the same time as unwanted operation must be avoided. Typical setting is 90 – 200ms (also dependent of re-trip timer).

The minimum time delay for the re-trip can be estimated as:

$$t2 \geq t1 + t_{cbopen} + t_{BFP\_reset} + t_{margin}$$

(Equation 46)

where:

t_{cbopen}	is the maximum opening time for the circuit breaker
t_{BFP_reset}	is the maximum time for breaker failure protection to detect correct breaker function (the current criteria reset)
t_{margin}	is a safety margin

It is often required that the total fault clearance time shall be less than a given critical time. This time is often dependent of the ability to maintain transient stability in case of a fault close to a power plant.

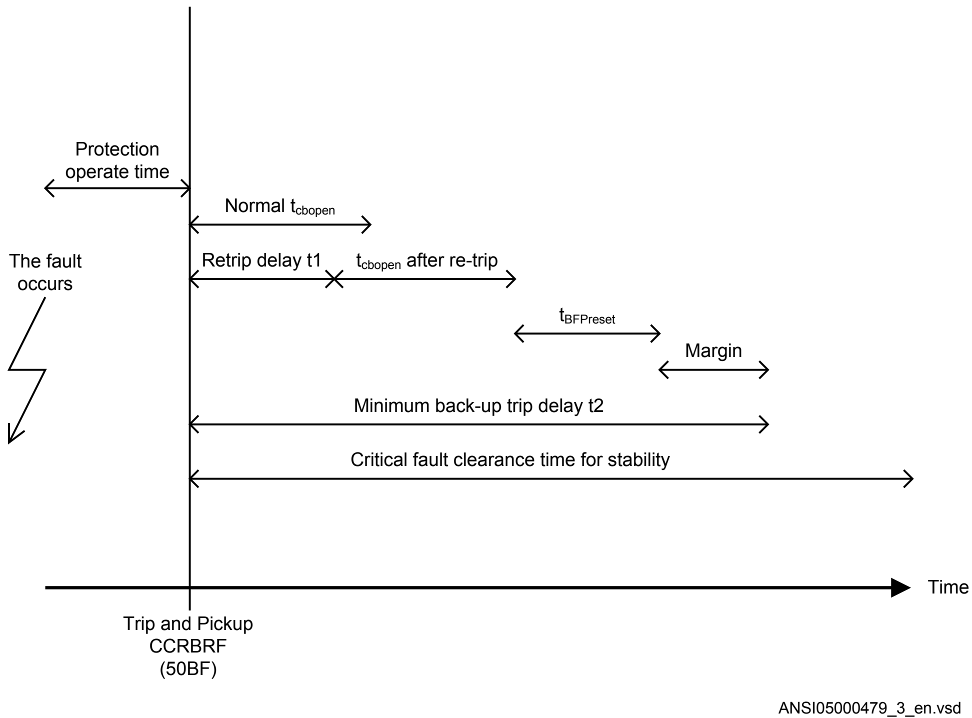


Figure 77: Time sequence

8.6 Pole discrepancy protection CCRPLD (52PD)

8.6.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Pole discrepancy protection	CCRPLD	PD	52PD

8.6.2 Application

There is a risk that a circuit breaker will get discrepancy between the poles at circuit breaker operation: closing or opening. One pole can be open and the other two closed, or two poles can be open and one closed. Pole discrepancy of a circuit breaker will cause unsymmetrical currents in the power system. The consequence of this can be:

- Negative sequence currents that will give stress on rotating machines
- Zero sequence currents that might give unwanted operation of sensitive ground-fault protections in the power system.

It is therefore important to detect situations with pole discrepancy of circuit breakers. When this is detected the breaker should be tripped directly.

Pole discordance protection CCRPLD (52PD) will detect situation with deviating positions of the poles of the protected circuit breaker. The protection has two different options to make this detection:

- By connecting the auxiliary contacts in the circuit breaker so that logic is created and a signal can be sent to the pole discrepancy protection, indicating pole discrepancy.
- Each phase current through the circuit breaker is measured. If the difference between the phase currents is larger than a *CurrUnsymPU* this is an indication of pole discrepancy, and the protection will operate.

8.6.3 Setting guidelines

The parameters for the Pole discordance protection CCRPLD (52PD) are set via the local HMI or PCM600.

The following settings can be done for the pole discrepancy protection.

GlobalBaseSel: Selects the global base value group used by the function to define (*IBase*), (*VBase*) and (*SBase*).

Operation: *Disabled* or *Enabled*

tTrip: Time delay of the operation.

ContactSel: Operation of the contact based pole discrepancy protection. Can be set: *Disabled*/*PD signal from CB*. If *PD signal from CB* is chosen the logic to detect pole discrepancy is made in the vicinity to the breaker auxiliary contacts and only one signal is connected to the pole discrepancy function.

CurrentSel: Operation of the current based pole discrepancy protection. Can be set: *Disabled*/*CB oper monitor*/*Continuous monitor*. In the alternative *CB oper monitor* the function is activated only directly in connection to breaker open or close command (during 200 ms). In the alternative *Continuous monitor* function is continuously activated.

CurrUnsymPU: Unsymmetrical magnitude of lowest phase current compared to the highest, set in % of the highest phase current.

CurrRelPU: Current magnitude for release of the function in % of *IBase*.

8.7 Directional over-/under-power protection GOPPDOP/ GUPPDUP (32/37)

8.7.1 Application

The task of a generator in a power plant is to convert mechanical energy available as a torque on a rotating shaft to electric energy.

Sometimes, the mechanical power from a prime mover may decrease so much that it does not cover bearing losses and ventilation losses. Then, the synchronous generator becomes a synchronous motor and starts to take electric power from the rest of the power system. This operating state, where individual synchronous machines operate as motors, implies no risk for the machine itself. If the generator under consideration is very large and if it consumes lots of electric power, it may be desirable to disconnect it to ease the task for the rest of the power system.

Often, the motoring condition may imply that the turbine is in a very dangerous state. The task of the reverse power protection is to protect the turbine and not to protect the generator itself.

Steam turbines easily become overheated if the steam flow becomes too low or if the steam ceases to flow through the turbine. Therefore, turbo-generators should have reverse power protection. There are several contingencies that may cause reverse power: break of a main steam pipe, damage to one or more blades in the steam turbine

or inadvertent closing of the main stop valves. In the last case, it is highly desirable to have a reliable reverse power protection. It may prevent damage to an otherwise undamaged plant.

During the routine shutdown of many thermal power units, the reverse power protection gives the tripping impulse to the generator breaker (the unit breaker). By doing so, one prevents the disconnection of the unit before the mechanical power has become zero. Earlier disconnection would cause an acceleration of the turbine generator at all routine shutdowns. This should have caused overspeed and high centrifugal stresses.

When the steam ceases to flow through a turbine, the cooling of the turbine blades will disappear. Now, it is not possible to remove all heat generated by the windage losses. Instead, the heat will increase the temperature in the steam turbine and especially of the blades. When a steam turbine rotates without steam supply, the electric power consumption will be about 2% of rated power. Even if the turbine rotates in vacuum, it will soon become overheated and damaged. The turbine overheats within minutes if the turbine loses the vacuum.

The critical time to overheating a steam turbine varies from about 0.5 to 30 minutes depending on the type of turbine. A high-pressure turbine with small and thin blades will become overheated more easily than a low-pressure turbine with long and heavy blades. The conditions vary from turbine to turbine and it is necessary to ask the turbine manufacturer in each case.

Power to the power plant auxiliaries may come from a station service transformer connected to the secondary side of the step-up transformer. Power may also come from a start-up service transformer connected to the external network. One has to design the reverse power protection so that it can detect reverse power independent of the flow of power to the power plant auxiliaries.

Hydro turbines tolerate reverse power much better than steam turbines do. Only Kaplan turbine and bulb turbines may suffer from reverse power. There is a risk that the turbine runner moves axially and touches stationary parts. They are not always strong enough to withstand the associated stresses.

Ice and snow may block the intake when the outdoor temperature falls far below zero. Branches and leaves may also block the trash gates. A complete blockage of the intake may cause cavitations. The risk for damages to hydro turbines can justify reverse power protection in unattended plants.

A hydro turbine that rotates in water with closed wicket gates will draw electric power from the rest of the power system. This power will be about 10% of the rated power. If there is only air in the hydro turbine, the power demand will fall to about 3%.

Diesel engines should have reverse power protection. The generator will take about 15% of its rated power or more from the system. A stiff engine may require perhaps 25% of the rated power to motor it. An engine that is good run in might need no more than 5%. It is necessary to obtain information from the engine manufacturer and to measure the reverse power during commissioning.

Gas turbines usually do not require reverse power protection.

Figure 78 illustrates the reverse power protection with underpower protection and with overpower protection. The underpower protection gives a higher margin and should provide better dependability. On the other hand, the risk for unwanted operation immediately after synchronization may be higher. One should set the underpower protection (reference angle set to 0) to trip if the active power from the generator is less than about 2%. One should set the overpower protection (reference angle set to 180) to trip if the power flow from the network to the generator is higher than 1%.

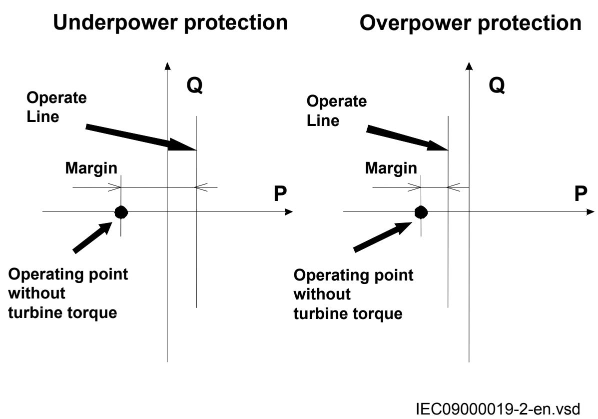


Figure 78: Reverse power protection with underpower or overpower protection

8.7.2 Directional overpower protection GOPPDOP (32)

8.7.2.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Directional overpower protection	GOPPDOP	P > →	32

8.7.2.2 Setting guidelines

GlobalBaseSel: Selects the global base value group used by the function to define (*IBase*), (*VBase*) and (*SBase*).

Operation: With the parameter *Operation* the function can be set *Enabled*/*Disabled*.

Mode: The voltage and current used for the power measurement. The setting possibilities are shown in table 24.

For reverse power applications *PosSeq* or *Arone* modes are strongly recommended.

Table 24: Complex power calculation

Set value *Mode*	Formula used for complex power calculation
A,B,C	$\overline{S} = \overline{V}_A \cdot \overline{I}_A^* + \overline{V}_B \cdot \overline{I}_B^* + \overline{V}_C \cdot \overline{I}_C^*$ (Equation 47)
Arone	$\overline{S} = \overline{V}_{AB} \cdot \overline{I}_A^* - \overline{V}_{BC} \cdot \overline{I}_C^*$ (Equation 48)
PosSeq	$\overline{S} = 3 \cdot \overline{V}_{PosSeq} \cdot \overline{I}_{PosSeq}^*$ (Equation 49)
A,B	$\overline{S} = \overline{V}_{AB} \cdot (\overline{I}_A^* - \overline{I}_B^*)$ (Equation 50)
B,C	$\overline{S} = \overline{V}_{BC} \cdot (\overline{I}_B^* - \overline{I}_C^*)$ (Equation 51)
C,A	$\overline{S} = \overline{V}_{CA} \cdot (\overline{I}_C^* - \overline{I}_A^*)$ (Equation 52)
A	$\overline{S} = 3 \cdot \overline{V}_A \cdot \overline{I}_A^*$ (Equation 53)
B	$\overline{S} = 3 \cdot \overline{V}_B \cdot \overline{I}_B^*$ (Equation 54)
C	$\overline{S} = 3 \cdot \overline{V}_C \cdot \overline{I}_C^*$ (Equation 55)

The function has two stages that can be set independently.

With the parameter *OpMode1(2)* the function can be set *Enabled*/*Disabled*.

The function gives trip if the power component in the direction defined by the setting *Angle1(2)* is larger than the set pick up power value *Power1(2)*

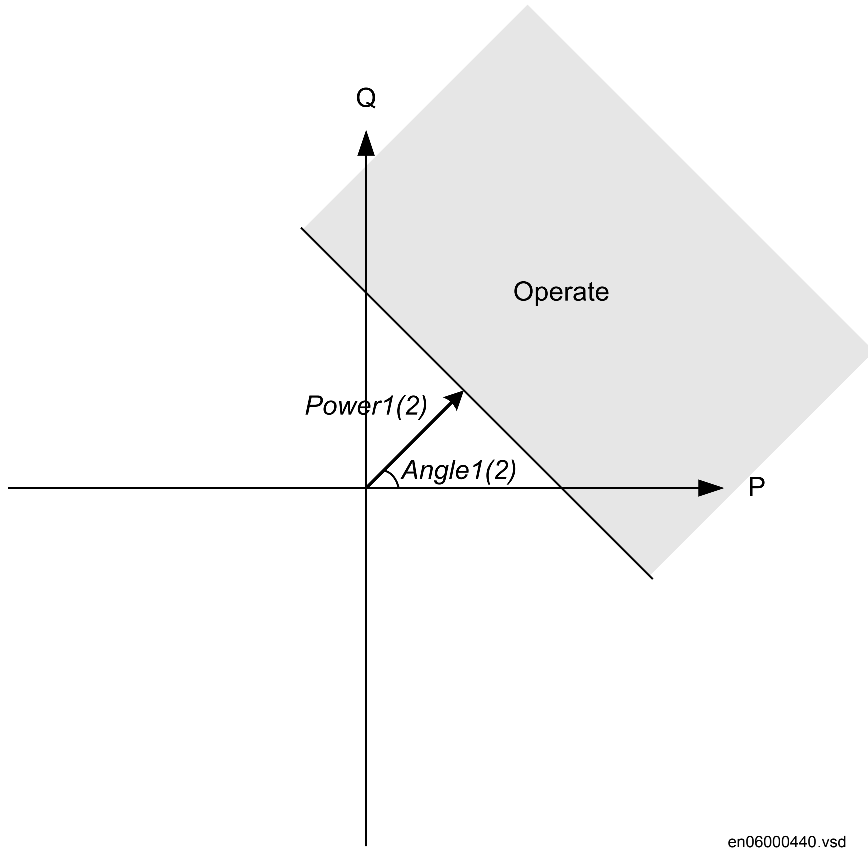


Figure 79: *Overpower mode*

The setting *Power1(2)* gives the power component pick up value in the *Angle1(2)* direction. The setting is given in p.u. of the generator rated power, see equation 56.

Minimum recommended setting is 1.0% of S_N. Note also that at the same time the minimum IED pickup current shall be at least 9 mA secondary.

$$S_N = \sqrt{3} \cdot VBase \cdot IBase$$

(Equation 56)

The setting *Angle1(2)* gives the characteristic angle giving maximum sensitivity of the power protection function. The setting is given in degrees. For active power the set angle should be 0° or 180°. 180° should be used for generator reverse power protection

in 50Hz network while -179.5° should be used for generator reverse power protection in 60Hz network. This angle adjustment in 60Hz networks will improve accuracy of the power function.

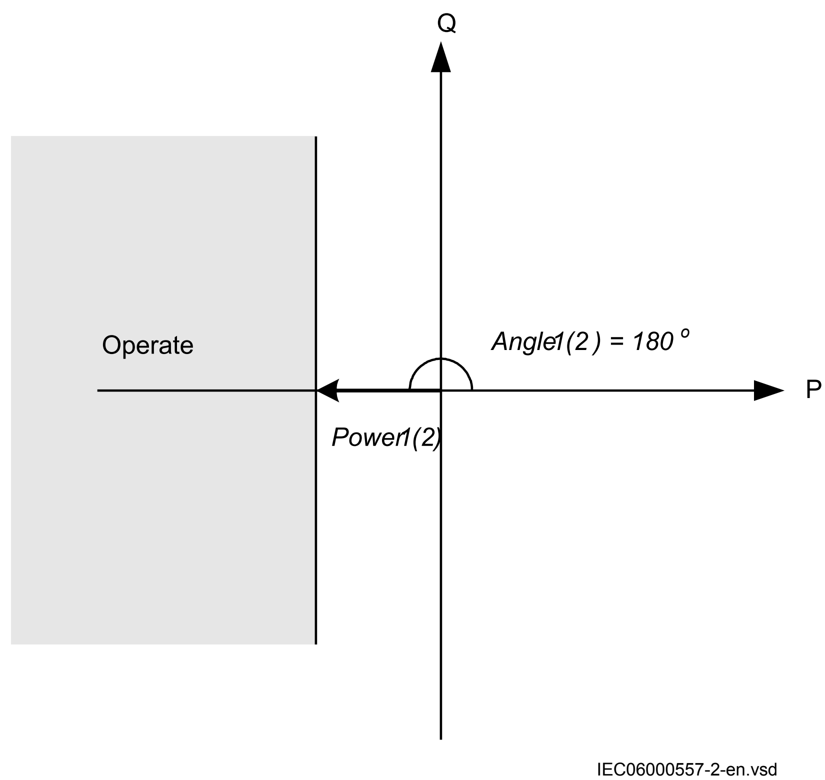


Figure 80: For reverse power the set angle should be 180° in the overpower function

TripDelay1(2) is set in seconds to give the time delay for trip of the stage after pick up.

The possibility to have low pass filtering of the measured power can be made as shown in the formula:

$$S = TD \cdot S_{Old} + (1 - TD) \cdot S_{Calculated}$$

(Equation 57)

Where	
S	is a new measured value to be used for the protection function
S_{old}	is the measured value given from the function in previous execution cycle
$S_{Calculated}$	is the new calculated value in the present execution cycle
TD	is settable parameter

The value of *TD=0.98* or even *TD=0.99* is recommended in generator reverse power applications as the trip delay is normally quite long. This filtering will improve accuracy of the power function.

8.7.3 Directional underpower protection GUPPDUP (37)

8.7.3.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Directional underpower protection	GUPPDUP	P < →	37

8.7.3.2 Setting guidelines

GlobalBaseSel: Selects the global base value group used by the function to define (*IBase*), (*VBase*) and (*SBase*).

Operation: With the parameter *Operation* the function can be set *Enabled*/*Disabled*.

Mode: The voltage and current used for the power measurement. The setting possibilities are shown in table 25.

For reverse power applications *PosSeq* or *Arone* modes are strongly recommended.

Table 25: Complex power calculation

Set value *Mode*	Formula used for complex power calculation
A, B, C	$\overline{S} = \overline{V}_A \cdot \overline{I}_A^{\,*} + \overline{V}_B \cdot \overline{I}_B^{\,*} + \overline{V}_C \cdot \overline{I}_C^{\,*}$ (Equation 58)
Arone	$\overline{S} = \overline{V}_{AB} \cdot \overline{I}_A^{\,*} - \overline{V}_{BC} \cdot \overline{I}_C^{\,*}$ (Equation 59)
PosSeq	$\overline{S} = 3 \cdot \overline{V}_{PosSeq} \cdot \overline{I}_{PosSeq}^{\,*}$ (Equation 60)
AB	$\overline{S} = \overline{V}_{AB} \cdot (\overline{I}_A^{\,*} - \overline{I}_B^{\,*})$ (Equation 61)

Table continues on next page

Set value *Mode*	Formula used for complex power calculation
BC	$$\bar{S} = \bar{V}_{BC} \cdot (\bar{I}_B^{\,*} - \bar{I}_C^{\,*})$$ (Equation 62)
CA	$$\bar{S} = \bar{V}_{CA} \cdot (\bar{I}_C^{\,*} - \bar{I}_A^{\,*})$$ (Equation 63)
A	$$\bar{S} = 3 \cdot \bar{V}_A \cdot \bar{I}_A^{\,*}$$ (Equation 64)
B	$$\bar{S} = 3 \cdot \bar{V}_B \cdot \bar{I}_B^{\,*}$$ (Equation 65)
C	$$\bar{S} = 3 \cdot \bar{V}_C \cdot \bar{I}_C^{\,*}$$ (Equation 66)

The function has two stages that can be set independently.

With the parameter *OpMode1(2)* the function can be set *Enabled*/*Disabled*.

The function gives trip if the power component in the direction defined by the setting *Angle1(2)* is smaller than the set pick up power value *Power1(2)*

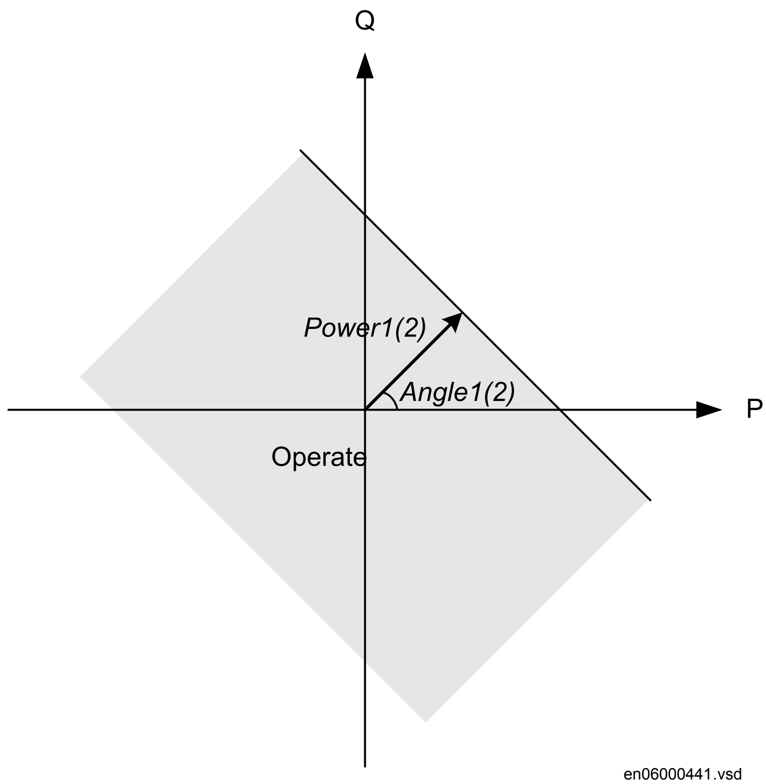


Figure 81: Underpower mode

The setting *Power1(2)* gives the power component pick up value in the *Angle1(2)* direction. The setting is given in p.u. of the generator rated power, see equation 67.

Minimum recommended setting is 1.0% of S_N. At the same time the minimum IED pickup current shall be at least 9 mA secondary.

$$S_N = \sqrt{3} \cdot VBase \cdot IBase$$

(Equation 67)

The setting *Angle1(2)* gives the characteristic angle giving maximum sensitivity of the power protection function. The setting is given in degrees. For active power the set angle should be 0° or 180°. 0° should be used for generator low forward active power protection.

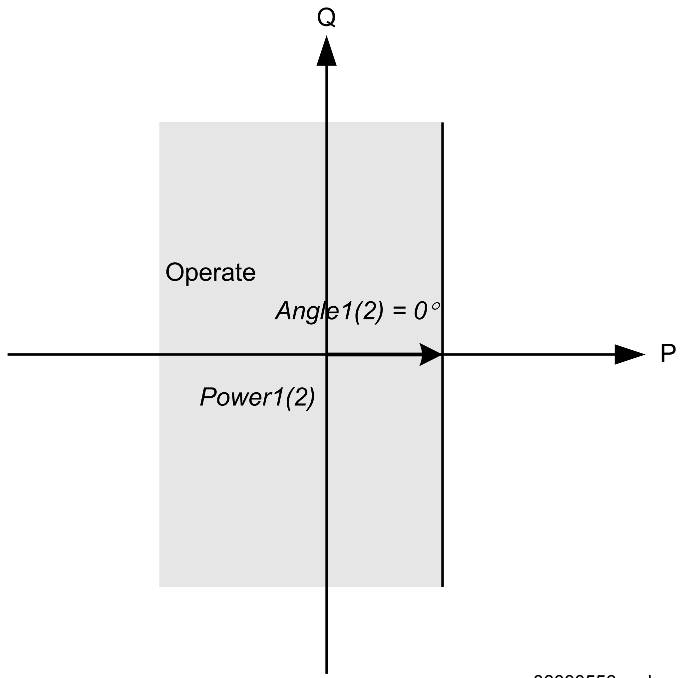


Figure 82: For low forward power the set angle should be 0° in the underpower function

TripDelay1(2) is set in seconds to give the time delay for trip of the stage after pick up.

The possibility to have low pass filtering of the measured power can be made as shown in the formula:

$$S = TD \cdot S_{Old} + (1 - TD) \cdot S_{Calculated}$$

(Equation 68)

Where

S	is a new measured value to be used for the protection function
S_{old}	is the measured value given from the function in previous execution cycle
$S_{Calculated}$	is the new calculated value in the present execution cycle
TD	is settable parameter

The value of *TD=0.98* or even *TD=0.99* is recommended in generator low forward power applications as the trip delay is normally quite long. This filtering will improve accuracy of the power function.

8.8 Accidental energizing protection for synchronous generator AEGGAPC (50AE)

8.8.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Accidental energizing protection for synchronous generator	AEGGAPC	U<I>	50AE

8.8.2 Application

Operating error, breaker head flashovers, control circuit malfunctions or a combination of these causes results in the generator being accidentally energized while offline. Three-phase energizing of a generator that is at standstill or on turning gears causes it to behave and accelerate similarly to an induction motor. The generator, at this point, essentially represent sub-transient reactance to the system and it can draw one to four per unit current depending upon the equivalent system impedance. This high current may thermally damage the generator in a few seconds.

Accidental energizing protection for synchronous generator AEGGAPC (50AE) monitors maximum phase current and maximum phase-to-phase voltage of the generator. In its basis it is “voltage supervised over current protection”. When generator voltage fails below preset level for longer than preset time delay an overcurrent protection stage is enabled. This overcurrent stage is intended to trip generator in case of an accidental energizing. When the generator voltage is high again this overcurrent stage is automatically disabled.

8.8.3 Setting guidelines

GlobalBaseSel: Selects the global base value group used by the function to define (*IBase*), (*VBase*) and (*SBase*).

IPickup: Level of current trip level when the function is armed, that is, at generator standstill, given in % of *IBase*. This setting should be based on evaluation of the largest current that can occur during the accidental energizing: Ienergisation. This current can be calculated as:

$$I_{energisation} = \frac{V_N / \sqrt{3}}{X_d'' + X_T + Z_{network}}$$

(Equation 69)

Where

V_N	is the rated voltage of the generator
X_d''	is the subtransient reactance for the generator (Ω)
X_T	is the reactance of the step-up transformer (Ω)
$Z_{network}$	is the short circuit source impedance of the connected network recalculated to the generator voltage level (Ω)

The setting can be chosen:

$$I > \textit{to be less than } 0.8 \cdot I_{energisation}$$

(Equation 70)

tOC: Time delay for trip in case of high current detection due to accidental energizing of the generator. The default value 0.03s is recommended.

27_pick_up: Voltage level, given in % of *VBase*, for activation (arming) of the accidental energizing protection function. This voltage shall be lower than the lowest operation voltage. The default value 50% is recommended.

tArm: Time delay of voltage under the level Arm< for activation. The time delay shall be longer than the longest fault time at short circuits or phase-ground faults in the network. The default value 5s is recommended.

59_Drop_out: Voltage level, given in % of *VBase*, for deactivation (dearming) of the accidental energizing protection function. This voltage shall be higher than the *27_pick_up* level. This setting level shall also be lower than the lowest operation voltage. The default value 80% is recommended.

tDisarm: Time delay of voltage over the level *59_Drop_out* for deactivation. The time delay shall be longer than *tOC*. The default value 0.5s is recommended.

8.9 Negative-sequence time overcurrent protection for machines NS2PTOC (46I2)

8.9.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Negative sequence time overcurrent protection for machines	NS2PTOC	2I2>	46I2

8.9.2 Application

Negative-sequence time overcurrent protection for machines NS2PTOC (46I2) is intended primarily for the protection of generators against possible overheating of the rotor caused by negative sequence current in the stator current.

The negative sequence currents in a generator may, among others, be caused by:

- Unbalanced loads
- Line to line faults
- Line to ground faults
- Broken conductors
- Malfunction of one or more poles of a circuit breaker or a disconnector

NS2PTOC (46I2) can also be used as a backup protection, that is, to protect the generator in case line protections or circuit breakers fail to clear unbalanced system faults.

To provide an effective protection for the generator for external unbalanced conditions, NS2PTOC (46I2) is able to directly measure the negative sequence current. NS2PTOC (46I2) also has a time delay characteristic which matches the heating characteristic of the generator $I_2^2 t = K$ as defined in standard IEEE C50.13.

where:

I_2	is negative sequence current expressed in per unit of the rated generator current
t	is operating time in seconds
K	is a constant which depends of the generators size and design

NS2PTOC (46I2) has a wide range of *K* settings and the sensitivity and capability of detecting and tripping for negative sequence currents down to the continuous capability of a generator.

A separate output is available as an alarm feature to warn the operator of a potentially dangerous situation.

8.9.2.1 Features

Negative-sequence time overcurrent protection NS2PTOC (46I2) is designed to provide a reliable protection for generators of all types and sizes against the effect of unbalanced system conditions.

The following features are available:

- Two steps, independently adjustable, with separate tripping outputs.
- Sensitive protection, capable of detecting and tripping for negative sequence currents down to 3% of rated generator current with high accuracy.
- Two time delay characteristics for step 1:
  - Definite time delay
  - Inverse time delay
- The inverse time overcurrent characteristic matches $I_2^2 t = K$ capability curve of the generators.
- Wide range of settings for generator capability constant *K* is provided, from 1 to 99 seconds, as this constant may vary greatly with the type of generator.
- Minimum trip time delay for inverse time characteristic, freely settable. This setting assures appropriate coordination with, for example, line protections.
- Maximum trip time delay for inverse time characteristic, freely settable.
- Inverse reset characteristic which approximates generator rotor cooling rates and provides reduced operate time if an unbalance reoccurs before the protection resets.
- Service value that is, measured negative sequence current value, in primary Amperes, is available through the local HMI.

8.9.2.2 Generator continuous unbalance current capability

During unbalanced loading, negative sequence current flows in the stator winding. Negative sequence current in the stator winding will induce double frequency current in the rotor surface and cause heating in almost all parts of the generator rotor.

When the negative sequence current increases beyond the generator's continuous unbalance current capability, the rotor temperature will increase. If the generator is not tripped, a rotor failure may occur. Therefore, industry standards has been established that determine generator continuous and short-time unbalanced current capabilities in terms of negative sequence current I_2 and rotor heating criteria $I_2^2 t$.

Typical short-time capability (referred to as unbalanced fault capability) expressed in terms of rotor heating criterion $I_2^2 t = K$ is shown below in Table 26.

Table 26: ANSI requirements for unbalanced faults on synchronous machines

Types of Synchronous Machine		Permissible $I_2^2 t = K\left[s\right]$
Salient pole generator		40
Synchronous condenser		30
Cylindrical rotor generators:	Indirectly cooled	30
	Directly cooled (0 – 800 MVA)	10
	Directly cooled (801 – 1600 MVA)	See Figure 83

Fig 83 shows a graphical representation of the relationship between generator I_2^2t capability and generator MVA rating for directly cooled (conductor cooled) generators. For example, a 500 MVA generator would have K = 10 seconds and a 1600 MVA generator would have K = 5 seconds. Unbalanced short-time negative sequence current I_2 is expressed in per unit of rated generator current and time t in seconds.

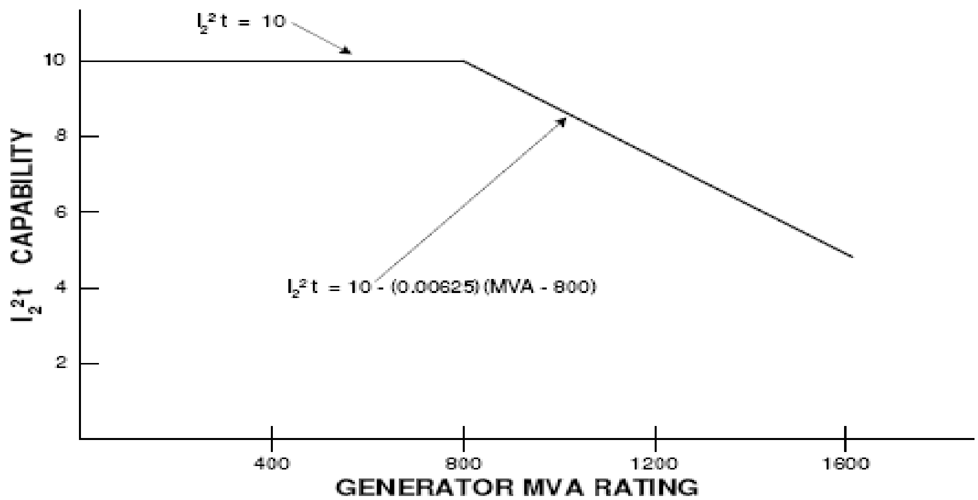


Figure 83: Short-time unbalanced current capability of direct cooled generators

Continuous I_2 - capability of generators is also covered by the standard. Table 27 below (from ANSI standard C50.13) contains the suggested capability:

Table 27: Continous I_2 capability

Type of generator		Permissible I_2 (in percent of rated generator current)
Salient Pole:	with damper winding	10
	without damper winding	5
Cylindrical Rotor		
Indirectly cooled		10
Directly cooled		
to 960 MVA		8
961 to 1200 MVA		6
1201 to 1500 MVA		5

As it is described in the table above that the continuous negative sequence current capability of the generator is in range of 5% to 10% of the rated generator current. During an open conductor or open generator breaker pole condition, the negative

sequence current can be in the range of 10% to 30% of the rated generator current. Other generator or system protections will not usually detect this condition and the only protection is the negative sequence overcurrent protection.

Negative sequence currents in a generator may be caused by:

- Unbalanced loads such as
  - Single phase railroad load
- Unbalanced system faults such as
  - Line to ground faults
  - Double line to ground faults
  - Line to line faults
- Open conductors, includes
  - Broken line conductors
  - Malfunction of one pole of a circuit breaker

.

8.9.3 Setting guidelines

8.9.3.1 Operate time characteristic

GlobalBaseSel: Selects the global base value group used by the function to define (*IBase*), (*VBase*) and (*SBase*).

Negative sequence time overcurrent protection for machines NS2PTOC (46I2) provides two operating time delay characteristics for step 1:

- Definite time delay characteristic
- Inverse time delay characteristic

The desired operate time delay characteristic is selected by setting *CurveType1* as follows:

- *CurveType1 = Definite*
- *CurveType1 = Inverse*

Step 2 always has a definite time delay characteristic. Definite time delay is independent of the magnitude of the negative sequence current once the pickup value is exceeded, while inverse time delay characteristic do depend on the magnitude of the negative sequence current.

This means that inverse time delay is long for a small overcurrent and becomes progressively shorter as the magnitude of the negative sequence current increases. Inverse time delay characteristic of the NS2PTOC (46I2) function is represented in the equation $I_2^2 t = K$, where the *K1* setting is adjustable over the range of *1 – 99* seconds. A typical inverse time overcurrent curve is shown in Figure 84.

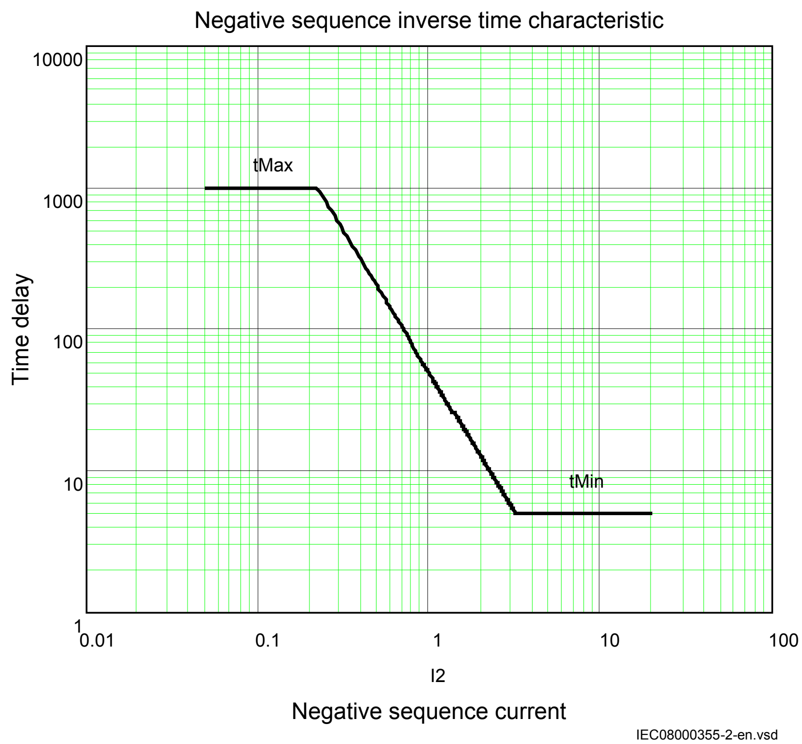


Figure 84: Inverse Time Delay characteristic

The example in figure 84 indicates that the protection function has a set minimum trip time *t1Min* of 5 sec. The setting *t1Min* is freely settable and is used as a security measure. This minimum setting assures appropriate coordination with for example line protections. It is also possible to set the upper time limit, *t1Max*.

8.9.3.2 Pickup sensitivity

The trip pickup levels Current *I2-1>* and *I2-2>* of NS2PTOC (46I2) are freely settable over a range of 3 to 500 % of rated generator current *IBase*. The wide range of pickup setting is required in order to be able to protect generators of different types and sizes.

After pickup, a certain hysteresis is used before resetting pickup levels. For both steps the reset ratio is 0.97.

8.9.3.3 Alarm function

The alarm function is operated by PICKUP signal and used to warn the operator for an abnormal situation, for example, when generator continuous negative sequence current capability is exceeded, thereby allowing corrective action to be taken before removing the generator from service. A settable time delay *tAlarm* is provided for the alarm function to avoid false alarms during short-time unbalanced conditions.

8.10 Voltage-restrained time overcurrent protection VR2PVOC(51V)

8.10.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Voltage-restrained time overcurrent protection	VR2PVOC	U<I>	51V

8.10.2 Application

A breakdown of the insulation between phase conductors or a phase conductor and ground results in a short-circuit or a ground fault. Such faults can result in large fault currents and may cause severe damage to the power system primary equipment.

The IED can be provided with a voltage-restrained time overcurrent protection (VR2PVOC, 51V). The VR2PVOC(51V) function is always connected to three-phase current and three-phase voltage input in the configuration tool, but it will always measure the maximum phase current and the minimum phase-to-phase voltage.

VR2PVOC(51V) function module has two independent protection elements built into it.

- One overcurrent step with the following built-in features:
  - Definite time delay or Inverse Time Overcurrent DT/IDMT delay
  - Voltage restrained/controlled feature is available in order to modify the pick-up level of the overcurrent stage in proportion to the magnitude of the measured voltage
- One undervoltage step with the following built-in feature:
  - Definite time delay

The undervoltage function can be enabled or disabled. Sometimes in order to obtain desired application functionality it is necessary to provide interaction between the two

protection elements within the VR2PVOC(51V) function by appropriate IED configuration (for example, overcurrent protection with under-voltage seal-in).

8.10.2.1 Base quantities

GlobalBaseSel: Selects the global base value group used by the function to define (*IBase*), (*VBase*) and (*SBase*).

IBase shall be entered as rated phase current of the protected object in primary amperes.

VBase shall be entered as rated phase-to-phase voltage of the protected object in primary kV.

8.10.2.2 Application possibilities

VR2PVOC(51V) function can be used in one of the following three applications:

- voltage controlled over-current
- voltage restrained over-current
- overcurrent protection with under-voltage seal-in.

8.10.2.3 Under-voltage seal-in

In the case of a static excitation system, which receives its power from the generator terminals, the magnitude of a sustained phase short-circuit current depends on the generator terminal voltage. In case of a nearby multi-phase fault, the generator terminal voltage may drop to quite low level, for example, <25% and the generator fault current may consecutively fall below the pickup of the overcurrent protection. The short-circuit current may drop below rated current after 0.5 - 1 s. Also, for generators with excitation system not fed from the generator terminals a fault can occur when the automatic voltage regulator is out of service. In such cases, to insure tripping under such conditions overcurrent protection with under-voltage seal-in feature can be used.

To adopt the VR2PVOC(51V) function the configuration is done according to figure 85. As seen in figure the pickup of the overcurrent stage will enable the under-voltage stage. Once enabled, the under-voltage stage will start a timer which causes function tripping, if the voltage does not recover above the set value. To ensure proper reset, the function is blocked two seconds after the trip signal is given.

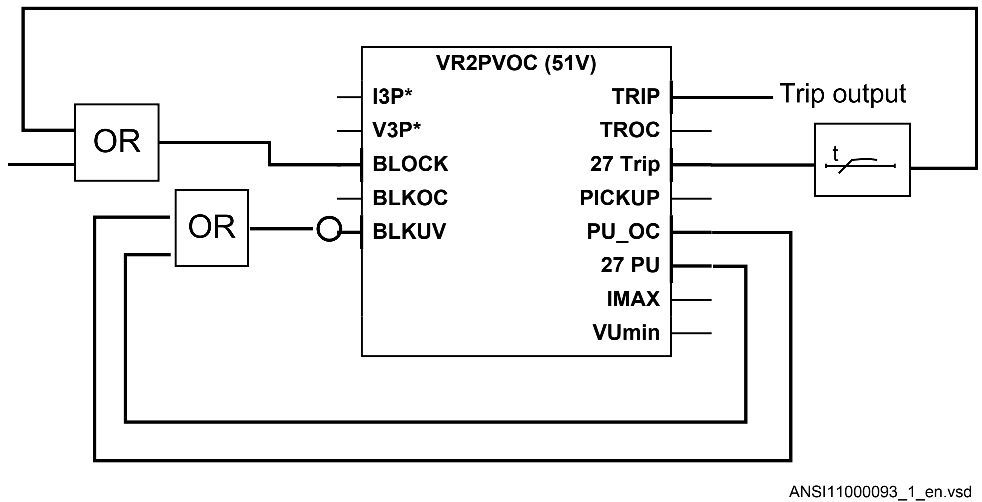


Figure 85: Under-voltage seal-in of current start

8.10.3 Setting guidelines

GlobalBaseSel: Selects the global base value group used by the function to define (*IBase*), (*VBase*) and (*SBase*).

8.10.3.1 Voltage restrained overcurrent protection for generator and step-up transformer

An example of how to use VR2PVOC (51V) function to provide voltage restrained overcurrent protection for a generator is given below. Let us assume that the time coordination study gives the following required settings:

- Inverse Time Over Current DT/IDMT curve: ANSI very inverse
- Pickup current of 185% of generator rated current at rated generator voltage
- Pickup current 25% of the original pickup current value for generator voltages below 25% of rated voltage

The following shall be done in order to ensure proper operation of the function:

1. Connect three-phase generator currents and voltages to VR2PVOC (51V).
2. Select the global base values there the VR2PVOC function is connected to.
3. Set the base voltage value to the rated generator phase-to-phase voltage in kV, and the rated generator current in primary ampere.
4. Select *Characterist* to match type of overcurrent curves used in the network for example *ANSI Very inv.*.
5. If required, set the minimum operating time for this curve by using the parameter *t_MinTripDelay* (default value 0.05s).

6. Set *PickupCurr* to value 185%.
7. Set *VDepMode* to *Slope*.
8. Set *VDepFact* to value 0.25.
9. Set *VHighLimit* to value 100%.

All other settings can be left at the default values.

8.10.3.2 Overcurrent protection with undervoltage seal-in

To obtain this functionality the following settings shall be first made for the overcurrent stage:

- set pickup from 135% to 150% of the generator rated current
- if over-current stage trip is not required set its time delay to 600.0s
- set parameter *VDepFact*=100% which will ensure constant overcurrent stage pickup irrespective of the magnitude of the generator voltage.

Operation_UV: The parameter *Operation_UV* is set *Enabled* to activate the under-voltage stage.

PickUp_Volt: Under-voltage level pickup in % of *VBase*. Typical setting is 70% to 80% of the generator rated voltage.

EnBlkLowV: Set it to *Disabled* in order to disable the low-voltage cut-off.

BlkLowVolt: Cut-off level for low-voltage part in % of *VBase*. This feature enabled by setting *EnBlkLowV*. The default value of the setting is 3.0% of *VBase* and in most cases, this will be a suitable value.

tDef_UV: The time delay between start and trip of the under-voltage stage. Since, this is the backup protection function long time delays are typically used for example, 3.0s.

Section 9 Voltage protection

9.1 Two step undervoltage protection UV2PTUV (27)

9.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Two step undervoltage protection	UV2PTUV	2U<	27

9.1.2 Application

Two-step undervoltage protection function (UV2PTUV ,27) is applicable in all situations, where reliable detection of low phase voltages is necessary. It is used also as a supervision and fault detection function for other protection functions, to increase the security of a complete protection system.

UV2PTUV (27) is applied to power system elements, such as generators, transformers, motors and power lines in order to detect low voltage conditions. Low voltage conditions are caused by abnormal operation or fault in the power system. UV2PTUV (27) is used in combination with overcurrent protections, either as restraint or in logic "and gates" of the trip signals issued by the two functions. Other applications are the detection of "no voltage" condition, for example, before the energization of a HV line or for automatic breaker trip in case of a blackout. UV2PTUV (27) is also used to initiate voltage correction measures, like insertion of shunt capacitor banks to compensate for reactive load and thereby increasing the voltage. The function has a high measuring accuracy to allow applications to control reactive load.

UV2PTUV (27) is used to disconnect apparatuses, like electric motors, which will be damaged when subject to service under low voltage conditions. UV2PTUV (27) deals with low voltage conditions at power system frequency, which can be caused by the following reasons:

1. Malfunctioning of a voltage regulator or wrong settings under manual control (symmetrical voltage decrease).
2. Overload (symmetrical voltage decrease).
3. Short circuits, often as phase-to-ground faults (unsymmetrical voltage decrease).

UV2PTUV (27) prevents sensitive equipment from running under conditions that could cause their overheating and thus shorten their life time expectancy. In many cases, it is a useful function in circuits for local or remote automation processes in the power system.

9.1.3 Setting guidelines

All the voltage conditions in the system where UV2PTUV (27) performs its functions should be considered. The same also applies to the associated equipment, its voltage and time characteristic.

There is a very wide application area where general undervoltage functions are used. All voltage related settings are made as a percentage of the global settings base voltage *VBase*, which normally is set to the primary rated voltage level (phase-to-phase) of the power system or the high voltage equipment under consideration.

The setting for UV2PTUV (27) is normally not critical, since there must be enough time available for the main protection to clear short circuits andground faults.

Some applications and related setting guidelines for the voltage level are described in the following sections.

9.1.3.1 Equipment protection, such as for motors and generators

The setting must be below the lowest occurring "normal" voltage and above the lowest acceptable voltage for the equipment.

9.1.3.2 Disconnected equipment detection

The setting must be below the lowest occurring "normal" voltage and above the highest occurring voltage, caused by inductive or capacitive coupling, when the equipment is disconnected.

9.1.3.3 Power supply quality

The setting must be below the lowest occurring "normal" voltage and above the lowest acceptable voltage, due to regulation, good practice or other agreements.

9.1.3.4 Voltage instability mitigation

This setting is very much dependent on the power system characteristics, and thorough studies have to be made to find the suitable levels.

9.1.3.5 Backup protection for power system faults

The setting must be below the lowest occurring "normal" voltage and above the highest occurring voltage during the fault conditions under consideration.

9.1.3.6 Settings for Two step undervoltage protection

The following settings can be done for two step undervoltage protection (UV2PTUV , 27).

GlobalBaseSel: Selects the global base value group used by the function to define (*IBase*), (*VBase*) and (*SBase*).

ConnType: Sets whether the measurement shall be phase-to-ground fundamental value, phase-to-phase fundamental value, phase-to-ground RMS value or phase-to-phase RMS value.

Operation: *Disabled/Enabled*.

UV2PTUV (27) measures selectively phase-to-ground voltages, or phase-to-phase voltage chosen by the setting *ConnType*.

This means operation for phase-to-ground voltage if:

$$V < (\%) \cdot VBase(kV) \Big/ \sqrt{3}$$

(Equation 71)

and operation for phase-to-phase voltage if:

$$\mathrm{Vpickup} < (\%) \cdot \mathrm{VBase(kV)}$$

(Equation 72)

Characteristic1: This parameter gives the type of time delay to be used for step 1. The setting can be. *Definite time/Inverse Curve A/Inverse Curve B*. The choice is highly dependent of the protection application.

OpModen: This parameter describes how many of the three measured voltages that should be below the set level to give operation for step *n* (*n*=step 1 and 2). The setting can be *1 out of 3*, *2 out of 3* or *3 out of 3*. It is sufficient that one phase voltage is low to

give operation. If the function shall be insensitive for single phase-to-ground faults *2 out of 3* can be chosen.

Pickupn: Set undervoltage operation value for step *n* (*n*=step 1 and 2), given as % of the global parameter *VBase*. This setting is highly dependent of the protection application. Here it is essential to consider the minimum voltage at non-faulted situations. This voltage is larger than 90% of nominal voltage.

tn: Time delay for step *n* (*n*=step 1 and 2), given in s. This setting is highly dependent of the protection application. In many applications the protection function does not directly trip where there is short circuit or ground faults in the system. The time delay must be coordinated to the short circuit protection.

t1Min: Minimum operating time for inverse time characteristic for step 1, given in s. When using inverse time characteristic for the undervoltage function during very low voltages can give a short operation time. This might lead to unselective trip. By setting *t1Min* longer than the operation time for other protections such unselective tripping can be avoided.

TD1: Time multiplier for inverse time characteristic. This parameter is used for coordination between different inverse time delayed undervoltage protections.

The function must be externally blocked when the protected object is disconnected.

9.2 Two step overvoltage protection OV2PTOV (59)

9.2.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Two step overvoltage protection	OV2PTOV	*2U>*	59

9.2.2 Application

Two step overvoltage protection OV2PTOV (59) is applicable in all situations, where reliable detection of high voltage is necessary. OV2PTOV (59) is used for supervision and detection of abnormal conditions, which, in combination with other protection functions, increase the security of a complete protection system.

High overvoltage conditions are caused by abnormal situations in the power system. OV2PTOV (59) is applied to power system elements, such as generators, transformers, motors and power lines in order to detect high voltage conditions. OV2PTOV (59) is used in combination with low current signals, to identify a transmission line, open in the remote end. In addition to that, OV2PTOV (59) is also used to initiate voltage correction measures, like insertion of shunt reactors, to compensate for low load, and thereby decreasing the voltage. The function has a high measuring accuracy and hysteresis setting to allow applications to control reactive load.

OV2PTOV (59) is used to disconnect apparatuses, like electric motors, which will be damaged when subject to service under high voltage conditions. It deals with high voltage conditions at power system frequency, which can be caused by:

1. Different kinds of faults, where a too high voltage appears in a certain power system, like metallic connection to a higher voltage level (broken conductor falling down to a crossing overhead line, transformer flash over fault from the high voltage winding to the low voltage winding and so on).
2. Malfunctioning of a voltage regulator or wrong settings under manual control (symmetrical voltage decrease).
3. Low load compared to the reactive power generation (symmetrical voltage decrease).
4. Ground-faults in high impedance grounded systems causes, beside the high voltage in the neutral, high voltages in the two non-faulted phases, (unsymmetrical voltage increase).

OV2PTOV (59) prevents sensitive equipment from running under conditions that could cause their overheating or stress of insulation material, and, thus, shorten their life time expectancy. In many cases, it is a useful function in circuits for local or remote automation processes in the power system.

9.2.3 Setting guidelines

The parameters for Two step overvoltage protection (OV2PTOV ,59) are set via the local HMI or PCM600.

All the voltage conditions in the system where OV2PTOV (59) performs its functions should be considered. The same also applies to the associated equipment, its voltage and time characteristic.

There is a very wide application area where general overvoltage functions are used. All voltage related settings are made as a percentage of a settable base primary voltage, which normally is set to the nominal voltage level (phase-to-phase) of the power system or the high voltage equipment under consideration.

The time delay for the OV2PTOV (59) can sometimes be critical and related to the size of the overvoltage - a power system or a high voltage component can withstand smaller overvoltages for some time, but in case of large overvoltages the related equipment should be disconnected more rapidly.

Some applications and related setting guidelines for the voltage level are given below:

Equipment protection, such as for motors, generators, reactors and transformers

High voltage can cause overexcitation of the core and deteriorate the winding insulation. The setting must be above the highest occurring "normal" voltage and below the highest acceptable voltage for the equipment.

Equipment protection, capacitors

High voltage can deteriorate the dielectricum and the insulation. The setting must be above the highest occurring "normal" voltage and below the highest acceptable voltage for the capacitor.

High impedance grounded systems

In high impedance grounded systems, ground-faults cause a voltage increase in the non-faulty phases. OV2PTOV (59) can be used to detect such faults. The setting must be above the highest occurring "normal" voltage and below the lowest occurring voltage during faults. A metallic single-phase ground-fault causes the non-faulted phase voltages to increase a factor of $\sqrt{3}$.

The following settings can be done for Two step overvoltage protection

GlobalBaseSel: Selects the global base value group used by the function to define (*IBase*), (*VBase*) and (*SBase*).

ConnType: Sets whether the measurement shall be phase-to-ground fundamental value, phase-to-phase fundamental value, phase-to-ground RMS value or phase-to-phase RMS value.

Operation: Disabled/Enabled .

OV2PTOV (59) measures the phase-to-ground voltages, or phase-to-phase voltages as selected. The function will operate if the voltage gets higher than the set percentage of the global set base voltage *VBase*. This means operation for phase-to-ground voltage over:

$$V > (\%) \cdot VBase(kV) / \sqrt{3}$$

(Equation 73)

and operation for phase-to-phase voltage over:

$$\text{Vpickup} > (\%) \cdot \text{VBase(kV)}$$

(Equation 74)

Characteristic1: This parameter gives the type of time delay to be used. The setting can be. *Definite time/Inverse Curve A/Inverse Curve B/Inverse Curve C*. The choice is highly dependent of the protection application.

OpModen: This parameter describes how many of the three measured voltages that should be above the set level to give operation for step n (n=step 1 and 2). The setting can be *1 out of 3, 2 out of 3 or 3 out of 3*. In most applications it is sufficient that one phase voltage is high to give operation. If the function shall be insensitive for single phase-to-ground faults *3 out of 3* can be chosen, because the voltage will normally rise in the non-faulted phases at single phase-to-ground faults.

Pickupn: Set overvoltage operating value for step n (n=step 1 and 2), given as % of the global parameter *VBase*. The setting is highly dependent of the protection application. Here it is essential to consider the Maximum voltage at non-faulted situations. Normally this voltage is less than 110% of nominal voltage.

tn: time delay for step n (n=step 1 and 2), given in s. The setting is highly dependent of the protection application. In many applications the protection function has the task to prevent damages to the protected object. The speed might be important for example in case of protection of transformer that might be overexcited. The time delay must be co-ordinated with other automated actions in the system.

t1Min: Minimum operating time for inverse time characteristic for step 1, given in s. For very high voltages the overvoltage function, using inverse time characteristic, can give very short operation time. This might lead to unselective trip. By setting *t1Min* longer than the operation time for other protections such unselective tripping can be avoided.

TD1: Time multiplier for inverse time characteristic. This parameter is used for co-ordination between different inverse time delayed undervoltage protections.

9.3 Two step residual overvoltage protection ROV2PTOV (59N)

9.3.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Two step residual overvoltage protection	ROV2PTOV	3U0>	59N

9.3.2 Application

Two step residual overvoltage protection ROV2PTOV (59N) is primarily used in high impedancegrounded distribution networks, mainly as a backup for the primary ground-fault protection of the feeders and the transformer. To increase the security for different ground-fault related functions, the residual overvoltage signal can be used as a release signal. The residual voltage can be measured either at the transformer neutral or from a voltage transformer open delta connection. The residual voltage can also be calculated internally, based on measurement of the three-phase voltages.

In high impedance grounded systems the residual voltage will increase in case of any fault connected to ground. Depending on the type of fault and fault resistance the residual voltage will reach different values. The highest residual voltage, equal to three times the phase-to-ground voltage, is achieved for a single phase-to-ground fault. The residual voltage increases approximately to the same level in the whole system and does not provide any guidance in finding the faulted component. Therefore, ROV2PTOV (59N) is often used as a backup protection or as a release signal for the feeder ground-fault protection.

9.3.3 Setting guidelines

All the voltage conditions in the system where ROV2PTOV (59N) performs its functions should be considered. The same also applies to the associated equipment, its voltage and time characteristic.

There is a very wide application area where general single input or residual overvoltage functions are used. All voltage related settings are made as a percentage of a settable base voltage, which can be set to the primary nominal voltage (phase-phase) level of the power system or the high voltage equipment under consideration.

The time delay for ROV2PTOV (59N) are seldom critical, since residual voltage is related to ground-faults in a high impedance grounded system, and enough time must normally be given for the primary protection to clear the fault. In some more specific situations, where the single overvoltage protection is used to protect some specific equipment, the time delay is shorter.

Some applications and related setting guidelines for the residual voltage level are given below.

9.3.3.1 Equipment protection, such as for motors, generators, reactors and transformers

High residual voltage indicates ground-fault in the system, perhaps in the component to which Two step residual overvoltage protection (ROV2PTOV, 59N) is connected. For selectivity reasons to the primary protection for the faulted device ROV2PTOV (59N) must trip the component with some time delay. The setting must be above the highest occurring "normal" residual voltage and below the highest acceptable residual voltage for the equipment

9.3.3.2 Stator ground-fault protection based on residual voltage measurement

Accidental contact between the stator winding in the slots and the stator core is the most common electrical fault in generators. The fault is normally initiated by mechanical or thermal damage to the insulating material or the anti-corona paint on a stator coil. Turn-to-turn faults, which normally are difficult to detect, quickly develop into an ground fault and are tripped by the stator ground-fault protection. Common practice in most countries is to ground the generator neutral through a resistor, which limits the maximum ground-fault current to 5-10 A primary. Tuned reactors, which limits the ground-fault current to less than 1 A, are also used. In both cases, the transient voltages in the stator system during intermittent ground-faults are kept within acceptable limits, and ground-faults, which are tripped within a second from fault inception, only cause negligible damage to the laminations of the stator core.

A residual overvoltage function used for such protection can be connected to different transformers.

1. voltage (or distribution) transformer connected between the generator neutral point and ground.
2. three-phase-to-ground-connected voltage transformers on the generator HV terminal side (in this case the residual voltage is internally calculated by the IED).
3. broken delta winding of three-phase-to-ground voltage transformers connected on the generator HV terminal side.

These three connection options are shown in Figure 86. Depending on pickup setting and fault resistance, such function can typically protect 80-95 percent of the stator winding. Thus, the function is normally set to operate for faults located at 5 percent or more from the stator neutral point with a time delay setting of 0.5 seconds. Thus such function protects approximately 95 percent of the stator winding. The function also covers the generator bus, the low-voltage winding of the unit transformer and the high-voltage winding of the auxiliary transformer of the unit. The function can be set so low because the generator-grounding resistor normally limits the neutral voltage transmitted from the high-voltage side of the unit transformer in case of an ground fault on the high-voltage side to a maximum of 2-3 percent.

Units with a generator breaker between the transformer and the generator should also have a three-phase voltage transformer connected to the bus between the low-voltage winding of the unit transformer and the generator circuit breaker (function 3 in Figure 86). The open delta secondary VT winding is connected to a residual overvoltage function, normally set to 20-30 percent, which provides ground-fault protection for the transformer low-voltage winding and the section of the bus connected to it when the generator breaker is open.

The two-stage residual overvoltage function ROV2PTOV (59N) can be used for all three applications. The residual overvoltage function measures and operates only on the fundamental frequency voltage component. It has an excellent rejection of the third harmonic voltage component commonly present in such generator installations.

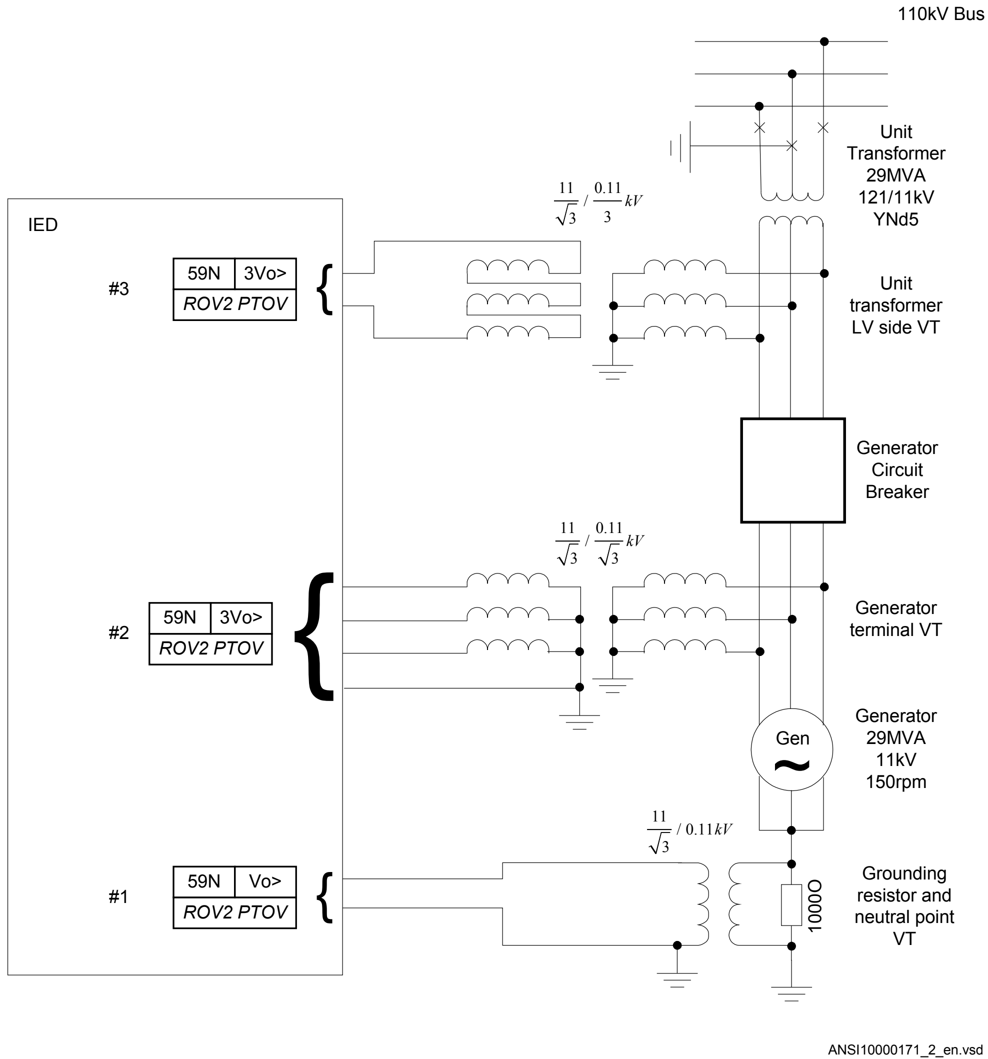


Figure 86: Voltage-based stator ground-fault protection

ROV2PTOV (59N) application #1

ROV2PTOV (59N) is here connected to a voltage (or distribution) transformer located at generator star point.

1. Due to such connection, ROV2PTOV (59N) measures the Uo voltage at the generator star point. Due to such connection, ROV2PTOV (59N) measures the Vo voltage at the generator star point. The maximum Vo voltage is present for a single phase-to-ground fault at the generator HV terminal and it has the maximum primary value:

$$Vo_{Max} = \frac{V_{Ph-Ph}}{\sqrt{3}} = \frac{11kV}{\sqrt{3}} = 6.35kV$$

(Equation 75)

2. One VT input is to be used in the IED. The VT ratio should be set according to the neutral point transformer ratio. For this application, the correct primary and secondary rating values are 6.35 kV and 110 V respectively.
3. For the base value, a generator-rated phase-to-phase voltage is to be set. Thus for this application *VBase=11 kV*.This base voltage value is not set directly under the function but it is instead selected by the *Global Base Value* parameter.
4. ROV2PTOV (59N) divides internally the set voltage base value with √3. Thus, the internally used base is equal to the maximum Vo value. Therefore, if wanted pickup is 5 percent from the neutral point, the ROV2PTOV (59N) pickup value is set to *Pickup1>=5%*.
5. The definite time delay is set to 0.5 seconds.

ROV2PTOV (59N) application #2

ROV2PTOV (59N) is here connected to a three-phase voltage transformer set located at generator HV terminal side.

1. Due to such connection, ROV2PTOV (59N) function calculates internally the 3Vo voltage (that is, 3Vo=VA+VB+VC) at the HV terminals of the generator. Maximum 3Vo voltage is present for a single phase-to-ground fault at the HV terminal of the generator and it has the maximum primary value $3Vo_{Max}$:

$$3Vo_{Max} = \sqrt{3} \cdot V_{Ph-Ph} = \sqrt{3} \cdot 11kV = 19.05kV$$

(Equation 76)

2. Three VT inputs are to be used in the IED. The VT ratio should be set according to the VT ratio. For this application, the correct primary and secondary VT rating values are 11 kV and 110 V respectively.
3. For the base value, a generator-rated phase-to-phase voltage is to be set. Thus for this application *VBase=11 kV*. This base voltage value is not set directly under the function but it is instead selected by the *Global Base Value* parameter.
4. ROV2PTOV (59N) divides internally the set voltage base value with √3. Thus internally used base voltage value is 6.35 kV. This is three times smaller than the maximum 3Vo voltage. Therefore, if the wanted start is 5 percent from the neutral point the ROV2PTOV (59N) pickup value is set to *Pickup1*=3·5 %=*15 %*(that is, three times the desired coverage).
5. The definite time delay is set to 0.5 seconds.

ROV2PTOV (59N) application #3

ROV2PTOV (59N) is here connected to an open delta winding of the VT located at the HV terminal side of the generator or the LV side of the unit transformer.

1. Due to such connection, ROV2PTOV (59N) measures the 3Vo voltage at generator HV terminals. Maximum 3Vo voltage is present for a single phase-to-ground fault at the HV terminal of the generator and it has the primary maximum value $3Vo_{Max}$:

$$3Vo_{Max} = \sqrt{3} \cdot V_{Ph-Ph} = \sqrt{3} \cdot 11kV = 19.05kV$$

(Equation 77)

2. One VT input is to be used in the IED. The VT ratio is to be set according to the open delta winding ratio. For this application correct primary and secondary rating values are 19.05 kV and 110 V respectively.
3. For the base value, a generator-rated phase-to-phase voltage is to be set. Thus for this application *VBase=11 kV*.This base voltage value is not set directly under the function but it is instead selected by the *Global Base Value* parameter.
4. ROV2PTOV (59N) internally divides the set voltage base value with √3. Thus, the internally used base voltage value is 6.35 kV. This is three times smaller than maximum 3Uo voltage. Therefore, if the wanted pickup is 5 percent from the neutral point the ROV2PTOV (59N) pickup value is set to *Pickup1*=3·5%=*15%* (that is, three times the desired coverage).
5. The definite time delay is set to 0.5 seconds.

9.3.3.3 Power supply quality

The setting must be above the highest occurring "normal" residual voltage and below the highest acceptable residual voltage, due to regulation, good practice or other agreements.

9.3.3.4 High impedance grounded systems

In high impedance grounded systems, ground faults cause a neutral voltage in the feeding transformer neutral. Two step residual overvoltage protection ROV2PTOV (59N) is used to trip the transformer, as a backup protection for the feeder ground-fault protection, and as a backup for the transformer primary ground-fault protection. The setting must be above the highest occurring "normal" residual voltage, and below the lowest occurring residual voltage during the faults under consideration. A metallic single-phase ground fault causes a transformer neutral to reach a voltage equal to the nominal phase-to-ground voltage.

The voltage transformers measuring the phase-to-ground voltages measure zero voltage in the faulty phase. The two healthy phases will measure full phase-to-phase voltage, as the ground is available on the faulty phase and the neutral has a full phase-to-ground voltage. The residual overvoltage will be three times the phase-to-ground voltage. See Figure 87.

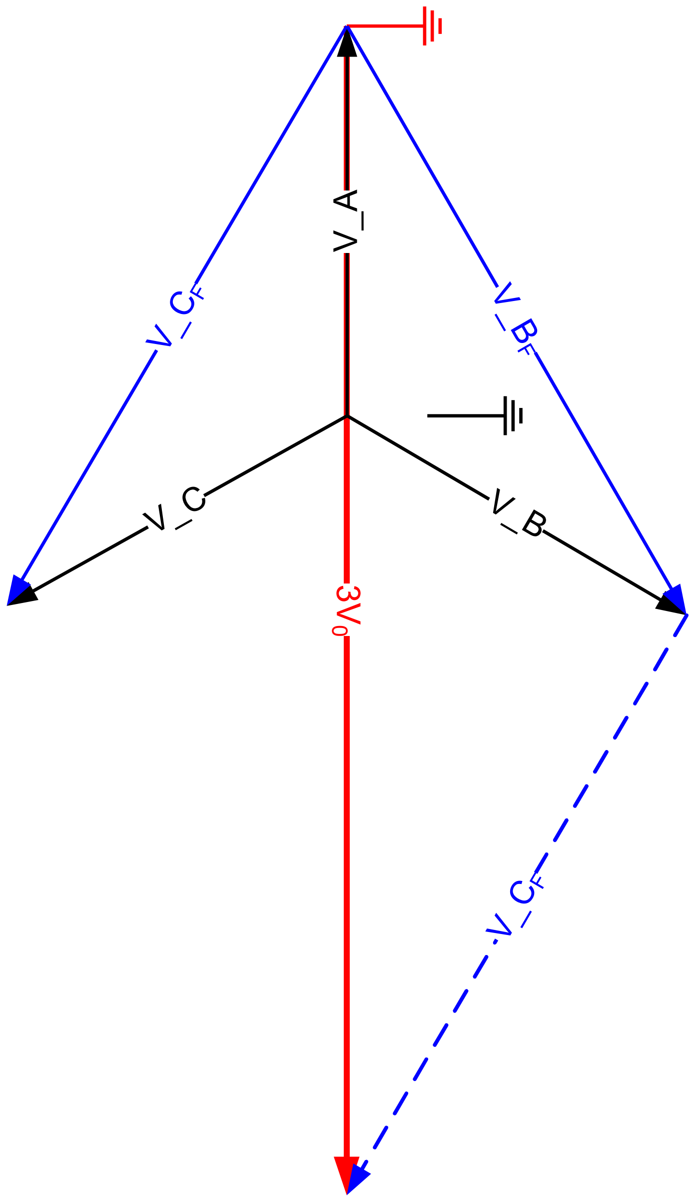


Figure 87: Ground fault in Non-effectively grounded systems

9.3.3.5 Direct grounded system

In direct grounded systems, an ground-fault on one phase indicates a voltage collapse in that phase. The two healthy phases will have normal phase-to-ground voltages. The residual sum will have the same value as phase-to-ground voltage. See Figure 88.

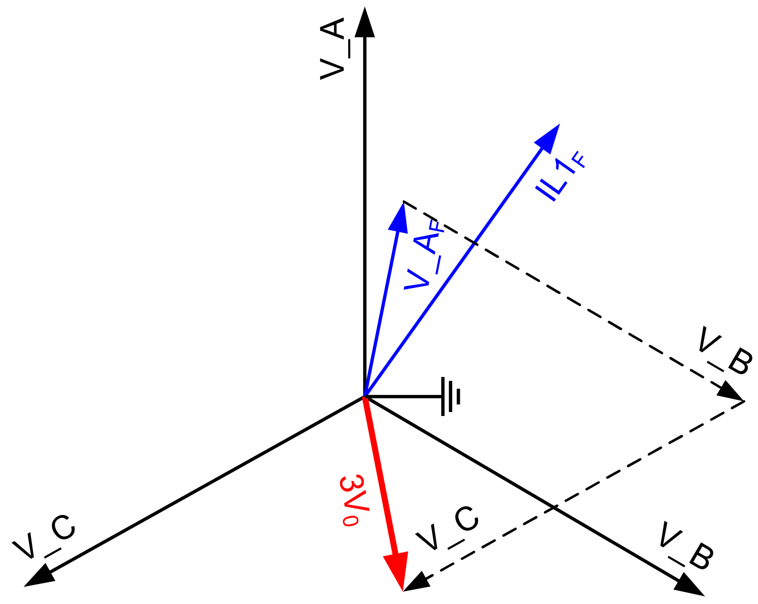


Figure 88: Ground fault in Direct grounded system

9.3.3.6 Settings for Two step residual overvoltage protection

GlobalBaseSel: Selects the global base value group used by the function to define (*IBase*), (*VBase*) and (*SBase*).

Operation: *Disabled* or *Enabled*

VBase is used as voltage reference for the voltage. The voltage can be fed to the IED in different ways:

1. The IED is fed from a normal voltage transformer group where the residual voltage is created from the phase-to-ground voltages within the protection software.
2. The IED is fed from a broken delta connection normal voltage transformer group. In a open delta connection the protection is fed by the voltage 3V0 (single input). The setting chapter in the application manual explains how the analog input needs to be set.
3. The IED is fed from a single voltage transformer connected to the neutral point of a power transformer in the power system. In this connection the protection is fed by the voltage VN=V0 (single input). The setting chapter in the application manual explains how the analog input needs to be set. ROV2PTOV (59N) will

measure the residual voltage corresponding nominal phase-to-ground voltage for high impedance grounded system. The measurement will be based on the neutral voltage displacement .

Characteristic1: This parameter gives the type of time delay to be used. The setting can be, *Definite time* or *Inverse curve A* or *Inverse curve B* or *Inverse curve C*. The choice is highly dependent of the protection application.

Pickupn: Set overvoltage operate value for step *n* (*n*=step 1 and 2), given as % of residual voltage corresponding to global set parameter *VBase*:

$$V > (\%) \cdot VBase(kV) / \sqrt{3}$$

The setting is dependent of the required sensitivity of the protection and the system grounding. In non-effectively grounded systems the residual voltage can be maximum the rated phase-to-ground voltage, which should correspond to 100%.

In effectively grounded systems this value is dependent of the ratio Z0/Z1. The required setting to detect high resistive ground-faults must be based on network calculations.

tn: time delay of step *n* (*n*=step 1 and 2), given in s. The setting is highly dependent of the protection application. In many applications, the protection function has the task to prevent damages to the protected object. The speed might be important for example in case of protection of transformer that might be overexcited. The time delay must be co-ordinated with other automated actions in the system.

t1Min: Minimum operate time for inverse time characteristic for step 1, given in s. For very high voltages the overvoltage function, using inverse time characteristic, can give very short operation time. This might lead to unselective trip. By setting *t1Min* longer than the operation time for other protections such unselective tripping can be avoided.

TD1: Time multiplier for inverse time characteristic. This parameter is used for co-ordination between different inverse time delayed undervoltage protections.

9.4 Overexcitation protection OEXPVPH (24)

9.4.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Overexcitation protection	OEXPVPH	U/f >	24

9.4.2 Application

The Overexcitation protection (OEXPVPH, 24) has current inputs to allow calculation of the load influence on the induced voltage. This gives a more exact measurement of the magnetizing flow. For power transformers with unidirectional load flow, the voltage to OEXPVPH (24) should therefore be taken from the feeder side.

Heat accumulated in critical parts during a period of overexcitation will be reduced gradually when the excitation returns to the normal value. If a new period of overexcitation occurs after a short time interval, the heating will start from a higher level, therefore, OEXPVPH (24) must have thermal memory. A fixed cooling time constant of 20 minutes is used.

The function should preferably be configured to use a three-phase voltage input if available. It then uses the positive sequence quantities of voltages and currents. When configured to a single phase-to-phase voltage input, a corresponding phase-to-phase current is calculated.

Analog measurements shall not be taken from any winding where a load tap changer is located.

Some different connection alternatives are shown in figure 89.

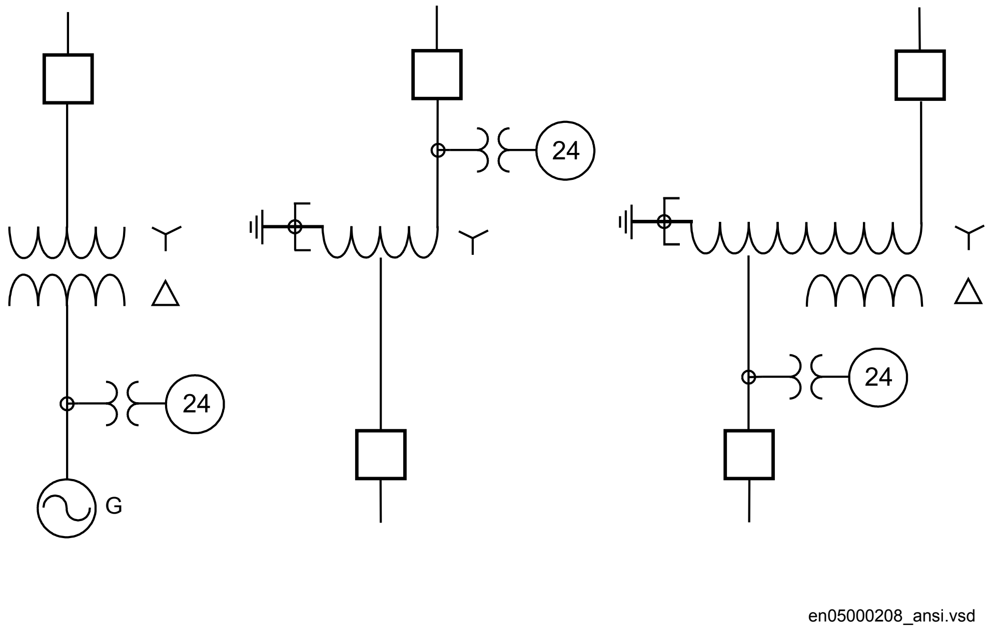


Figure 89: Alternative connections of an Overexcitation protection OEXPVPH (24) (Volt/Hertz)

9.4.3 Setting guidelines

9.4.3.1 Recommendations for input and output signals

Please refer to the Technical manual for a list of setting parameters.

Binary Input signals

BLOCK: The input will block the operation of the Overexcitation protection OEXPVPH (24). The block input can be used to block the operation for a limited time during special service conditions.

RESET: OEXPVPH (24) has a thermal memory, which can take a long time to reset. Activation of the RESET input will reset the function instantaneously.

Binary Output signals

BFI: The BFI output indicates that the setPickup1> level has been reached.

TRIP: The TRIP output is activated after the operate time for the V/f level has expired.

ALARM: The output is activated when the alarm level has been reached and the alarm timer has elapsed.

9.4.3.2 Settings

GlobalBaseSel: Selects the global base value group used by the function to define (*IBase*), (*VBase*) and (*SBase*).

Operation: The operation of the Overexcitation protection OEXPVPH (24) can be set to *Enabled*/*Disabled*.

Pickup1: Operating level for the inverse characteristic. The operation is based on the relation between rated voltage and rated frequency and set as a percentage factor. Normal setting is around 108-110% depending of the capability curve for the transformer/generator.

Pickup2: Operating level for the *t_MinTripDelay* definite time delay used at high overvoltages. The operation is based on the relation between rated voltage and rated frequency and set as a percentage factor. Normal setting is around 110-180% depending of the capability curve of the transformer/generator. Setting should be above the knee-point when the characteristic starts to be straight on the high side.

TDforIEEECurve: The time constant for the IEEE inverse characteristic. Select the one giving the best match to the transformer capability.

t_MinTripDelay: The operating times at voltages higher than the set *Pickup2*. The setting shall match capabilities on these high voltages. Typical setting can be 1-10 second.

AlarmPickup: Setting of the alarm level in percentage of the set trip level. The alarm level is normally set at around 98% of the trip level.

tAlarm: Setting of the time delay to alarm from when the alarm level has been reached. Typical setting is 5 seconds.

9.5 100% Stator ground fault protection, 3rd harmonic based STEFPHIZ (59THD)

9.5.1 Identification

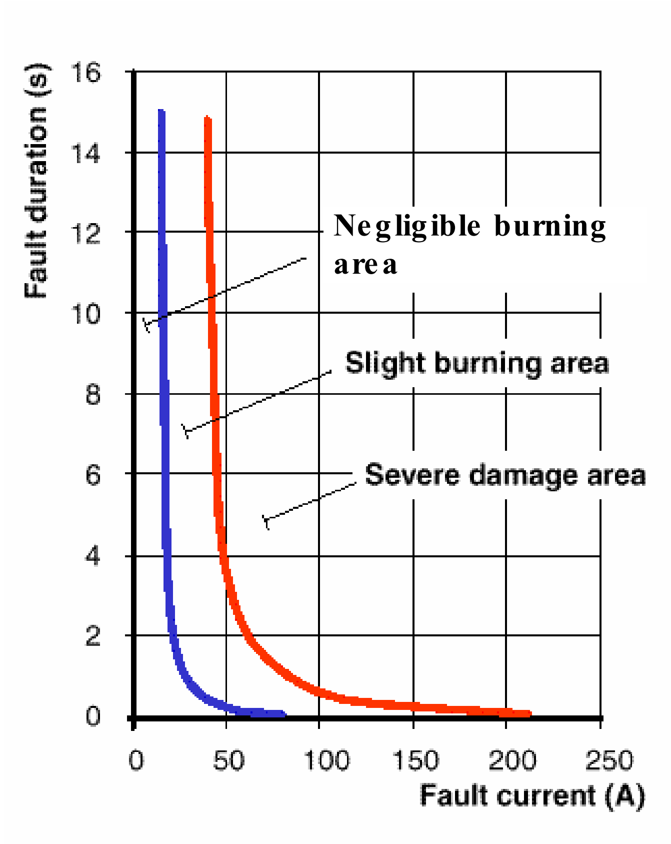
Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
100% Stator ground fault protection, 3rd harmonic based	STEFPHIZ	-	59THD

9.5.2 Application

The stator ground-fault protection of medium and large generators connected to their power transformers should preferably be able of detecting small ground current leakages (with equivalent resistances of the order of several kΩ) occurring even in the vicinity of the generator neutral. A high resistance ground fault close to the neutral is not critical itself, but must anyway be detected in order to prevent a double ground fault when another grounding fault occurs, for example near the generator terminals. Such a double fault can be disastrous.

Short-circuit between the stator winding in the slots and stator core is the most common type of electrical fault in generators. Medium and large generators normally have high impedance ground, that is, grounding via a neutral point resistor. This resistor is dimensioned to give an ground fault current in the range 3 – 15 A at a solid ground-fault directly at the generator high voltage terminal. The relatively small ground fault currents (of just one ground fault) give much less thermal and mechanical stress on the generator, compared, for example to short circuit between phases. Anyhow, the ground faults in the generator have to be detected and the generator has to be tripped, even if longer fault time, compared to short circuits, can be allowed.

The relation between the magnitude of the generator ground fault current and the fault time, with defined consequence, is shown in figure 90.



en06000316.vsd

Figure 90: Relation between the magnitude of the generator ground fault current and the fault time

As mentioned earlier, for medium and large generators, the common practice is to have high impedance grounding of generating units. The most common grounding system is to use a neutral point resistor, giving an ground fault current in the range 3 – 15 A at a non-resistive ground-fault at the high voltage side of the generator. One version of this kind of grounding is a single-phase distribution transformer, the high voltage side of which is connected between the neutral point and ground, and with an equivalent resistor on the low voltage side of the transformer. Other types of system grounding of generator units, such as direct grounding and isolated neutral, are used but are quite rare.

In normal non-faulted operation of the generating unit the neutral point voltage is close to zero, and there is no zero sequence current flow in the generator. When a phase-to-ground fault occurs the fundamental frequency neutral point voltage will increase and there will be a fundamental frequency current flow through the neutral point resistor.

To detect an ground-fault on the windings of a generating unit one may use a neutral point overvoltage protection, a neutral point overcurrent protection, a zero sequence

overvoltage protection or a residual differential protection. These protection schemes are simple and have served well during many years. However, at best these schemes protect only 95% of the stator winding. They leave 5% at the neutral end unprotected. Under unfavorable conditions the blind zone may extend to 20% from the neutral. Some different ground fault protection solutions are shown in figure 91 and figure 92.

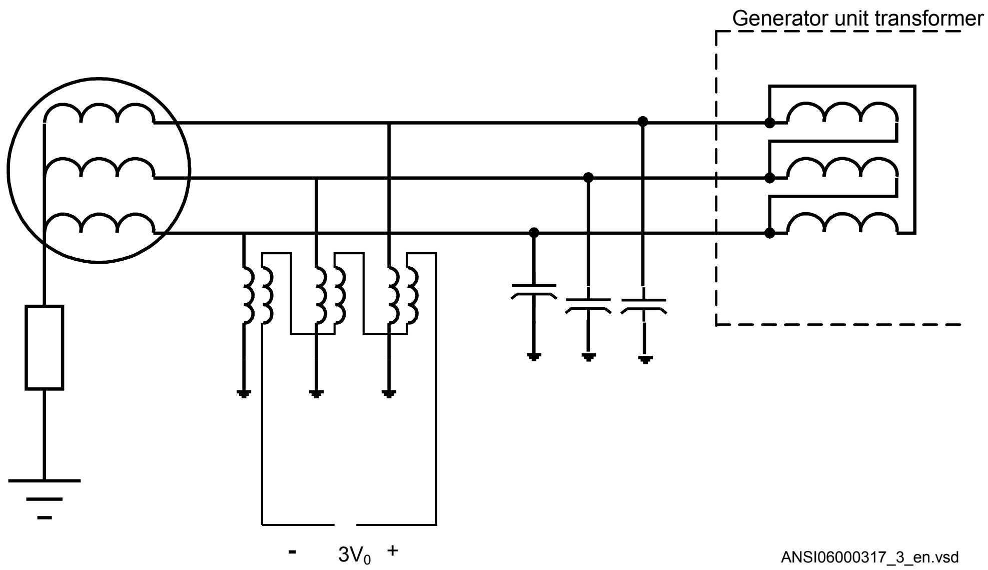


Figure 91: Broken delta voltage transformer measurement of $3V_0$ voltage

Alternatively zero sequence current can be measured as shown in fig 93

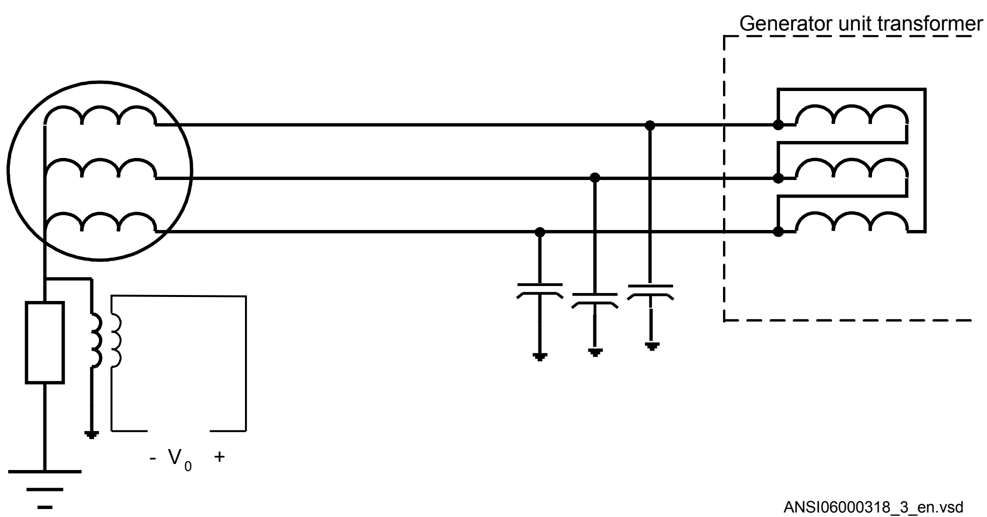


Figure 92: Neutral point voltage transformer measurement of neutral point voltage (that is V_0 voltage)

In some applications the neutral point resistor is connected to the low voltage side of a single-phase distribution transformer, connected to the generator neutral point. In such a case the voltage measurement can be made directly across the secondary resistor.

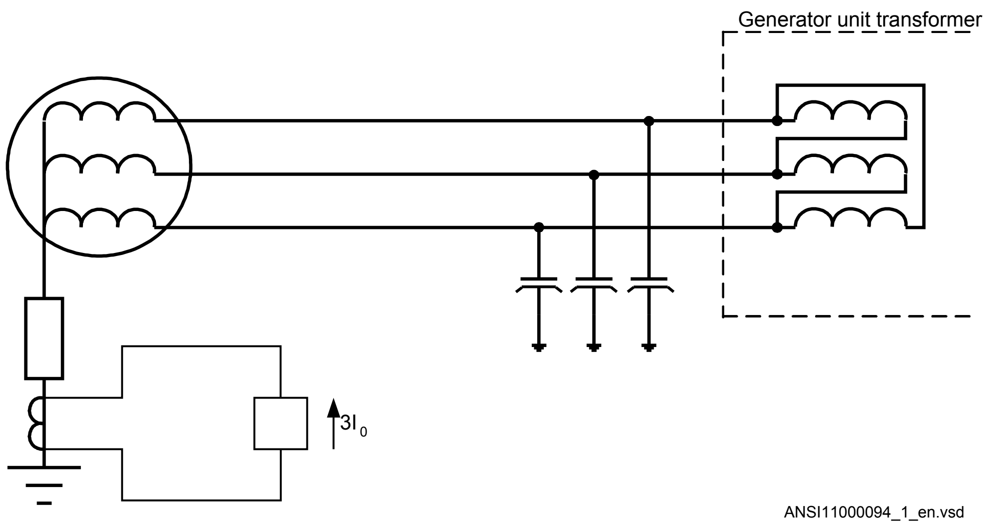


Figure 93: Neutral point current measurement

In some power plants the connection of the neutral point resistor is made to the generator unit transformer neutral point. This is often done if several generators are connected to the same bus. The detection of ground-fault can be made by current measurement as shown in figure 94.

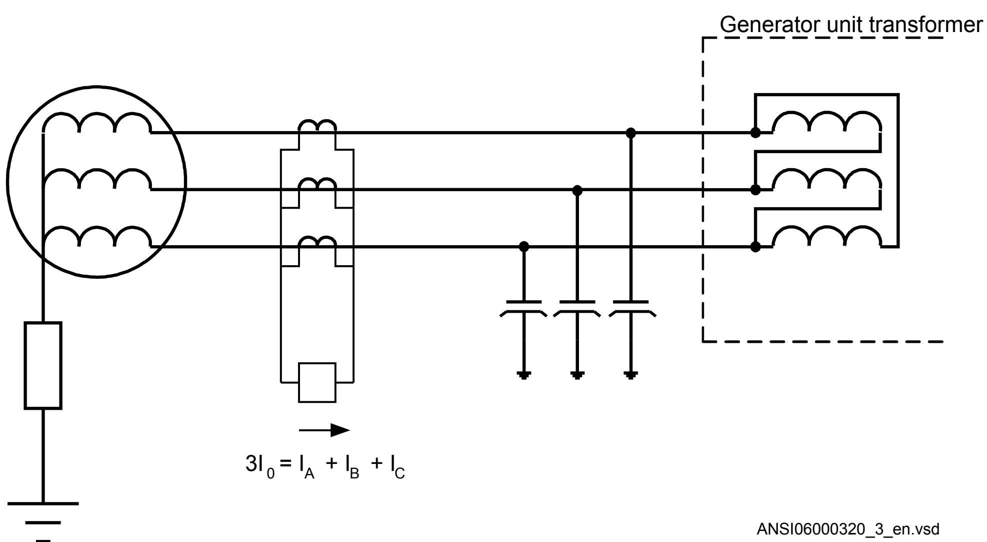


Figure 94: Residual current measurement

One difficulty with this solution is that the current transformer ratio is normally so large so that the secondary residual current will be very small. The false residual current, due to difference between the three phase current transformers, can be in the same range as the secondary ground fault current. Thus if physically possible, cable CT is recommended for such applications in order to measure $3I_0$ correct.

As indicated above, there will be very small neutral voltage or residual current if the stator ground fault is situated close to the generator neutral. The probability for this fault is quite small but not zero. For small generators the risk of not detecting the stator ground fault, close to the neutral, can be accepted. For medium and large generator it is however often a requirement that also theses faults have to be detected. Therefore, a special neutral end ground fault protection STEFPHIZ (59THD) is required. STEFPHIZ (59THD) can be realized in different ways. The two main principles are:

- 3^{rd} harmonic voltage detection
- Neutral point voltage injection

The 3^{rd} harmonic voltage detection is based on the fact that the generator generates some degree of 3^{rd} harmonic voltages. These voltages have the same phase angle in the three phases. This means that there will be a harmonic voltage in the generator neutral during normal operation. This component is used for detection of ground faults in the generator, close to the neutral.

If the 3^{rd} harmonic voltage generated in the generator, is less than 0.8 V RMS secondary, the 3^{rd} harmonic based protection cannot be used.

In this protection function, a 3^{rd} harmonic voltage differential principle is used.

9.5.3 Setting guidelines

The 100% Stator ground fault protection, 3rd harmonic based (STEFPHIZ, 59THD)protection is using the 3^{rd} harmonic voltage generated by the generator itself. To assure reliable function of the protection it is necessary that the 3^{rd} harmonic voltage generation is at least 1% of the generator rated voltage.

> Adaptive frequency tracking must be properly configured and set for the Signal Matrix for analog inputs (SMAI) preprocessing blocks in order to ensure proper operation of the generator differential protection function during varying frequency conditions.

Operation: The parameter *Operation* is used to set the function /*EnabledDisabled*.

Common base IED values for primary current (setting *IBase*), primary voltage (setting *VBase*) and primary power (setting *SBase*) are set in a Global base values for settings

function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values. The setting *VBase* is set to the rated phase to phase voltage in kV of the generator.

TVoltType: STEFPHIZ(59THD) function is fed from a voltage transformer in the generator neutral. *TVoltType* defines how the protection function is fed from voltage transformers at the high voltage side of the generator. The setting alternatives are:

- *NoVoltage* is used when no voltage transformers are connected to the generator terminals. In this case the protection will operate as a 3rd harmonic undervoltage protection.
- *ResidualVoltage* 3V0 is used if the protection is fed from a broken delta connected three-phase group of voltage transformers connected to the generator terminals. This is the recommended alternative.
- *AllThreePhases* is used when the protection is fed from the three phase voltage transformers. The third harmonic residual voltage is derived internally from the phase voltages.
- *PhaseA, PhaseB or PhaseC*, are used when there is only one phase voltage transformer available at the generator terminals.

The setting *beta* gives the proportion of the 3rd harmonic voltage in the neutral point of the generator to be used as restrain quantity. *beta* must be set so that there is no risk of trip during normal, non-faulted, operation of the generator. On the other hand, if *beta* is set high, this will limit the portion of the stator winding covered by the protection. The default setting 3.0 will in most cases give acceptable sensitivity for ground fault near to the neutral point of the stator winding. One possibility to assure best performance is to make measurements during normal operation of the generator. The protective function itself makes the required information available:

- VT3, the 3rd harmonic voltage at the generator terminal side
- VN3, the 3rd harmonic voltage at the generator neutral side
- E3, the induced harmonic voltage
- ANGLE, the phase angle between voltage phasors VT3 and VN3
- DV3, the differential voltage between VT3 and VN3; (|VT3 + VN3|)
- BV3, the bias voltage (*Beta x VN3*)

For different operation points (P and Q) of the generator the differential voltage DV3 can be compared to the bias BV3, and a suitable factor *beta* can be chosen to assure security.

CBexists: *CBexists* is set to *Yes* if there is a generator breaker (between the generator and the block transformer).

FactorCBopen: The setting *FactorCBopen* gives a constant to be multiplied to *beta* if the generator circuit breaker is open, input 52a is not active and *CBexists* is set to Yes .

VN3rdHPU: The setting *VN3rdHPU* gives the undervoltage operation level if *TVoltType* is set to *NoVoltage*. In all other connection alternatives this setting is not active and operation is instead based on comparison of the differential voltage DV3 with the bias voltage BV3. The setting is given as % of the rated phase-to-ground voltage. The setting should be based on neutral point 3rd harmonic voltage measurement at normal operation.

VNFundPU: *VNFundPU* gives the operation level for the fundamental frequency residual voltage stator ground fault protection. The setting is given as % of the rated phase-to-ground voltage. A normal setting is in the range 5 – 10%.

VT3BlkLevel:*VT3BlkLevel* gives a voltage level for the 3rd harmonic voltage level at the terminal side. If this level is lower than the setting the function is blocked. The setting is given as % of the rated phase-to-ground voltage. The setting is typically 1 %.

t3rdH: *t3rdH* gives the trip delay of the 3rd harmonic stator ground fault protection. The setting is given in seconds. Normally, a relatively long delay (about 10 s) is acceptable as the ground fault current is small.

tVNFund: *tVNFund* gives the trip delay of the fundamental frequency residual voltage stator ground fault protection. The setting is given in s. A delay in the range 0.5 – 2 seconds is acceptable.

9.6 Rotor ground fault protection (64R)

Generator rotor winding and its associated dc supply electric circuit is typically fully insulated from the ground. Therefore single connection of this circuit to ground will not cause flow of any substantial current. However, if second ground-fault appears in this circuit circumstances can be quit serious. Depending on the location of these two faults such operating condition may cause:

- Partial or total generator loss of field
- Large dc current flow through rotor magnetic circuit
- Rotor vibration
- Rotor displacement sufficient to cause stator mechanical damage

Therefore practically all bigger generators have some dedicated protection which is capable to detect the first ground-fault in the rotor circuit and then, depending on the fault resistance, either just to give an alarm to the operating personnel or actually to give stop command to the machine.

Rotor ground fault protection can be integrated in the IED among all other protection functions typically required for generator protection.

How this is achieved by using COMBIFLEX injection unit RXTTE4 is described in Instruction 1MRG001910.

Section 10 Frequency protection

10.1 Underfrequency protection SAPTUF (81)

10.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Underfrequency protection	SAPTUF	$f <$	81

10.1.2 Application

Underfrequency protection SAPTUF (81) is applicable in all situations, where reliable detection of low fundamental power system frequency is needed. The power system frequency, and the rate of change of frequency, is a measure of the unbalance between the actual generation and the load demand. Low fundamental frequency in a power system indicates that the available generation is too low to fully supply the power demanded by the load connected to the power grid. SAPTUF (81) detects such situations and provides an output signal, suitable for load shedding, generator boosting, HVDC-set-point change, gas turbine start up and so on. Sometimes shunt reactors are automatically switched in due to low frequency, in order to reduce the power system voltage and hence also reduce the voltage dependent part of the load.

SAPTUF (81) is very sensitive and accurate and is used to alert operators that frequency has slightly deviated from the set-point, and that manual actions might be enough. The underfrequency signal is also used for overexcitation detection. This is especially important for generator step-up transformers, which might be connected to the generator but disconnected from the grid, during a roll-out sequence. If the generator is still energized, the system will experience overexcitation, due to the low frequency.

10.1.3 Setting guidelines

All the frequency and voltage magnitude conditions in the system where SAPTUF (81) performs its functions should be considered. The same also applies to the associated equipment, its frequency and time characteristic.

There are two specific application areas for SAPTUF (81):

1. to protect equipment against damage due to low frequency, such as generators, transformers, and motors. Overexcitation is also related to low frequency
2. to protect a power system, or a part of a power system, against breakdown, by shedding load, in generation deficit situations.

The under frequency PICKUP value is set in Hz. All voltage magnitude related settings are made as a percentage of a global base voltage parameter. The UBase value should be set as a primary phase-to-phase value.

Some applications and related setting guidelines for the frequency level are given below:

Equipment protection, such as for motors and generators

The setting has to be well below the lowest occurring "normal" frequency and well above the lowest acceptable frequency for the equipment.

Power system protection, by load shedding

The setting has to be below the lowest occurring "normal" frequency and well above the lowest acceptable frequency for power stations, or sensitive loads. The setting level, the number of levels and the distance between two levels (in time and/or in frequency) depends very much on the characteristics of the power system under consideration. The size of the "largest loss of production" compared to "the size of the power system" is a critical parameter. In large systems, the load shedding can be set at a fairly high frequency level, and the time delay is normally not critical. In smaller systems the frequency PICKUP level has to be set at a lower value, and the time delay must be rather short.

10.2 Overfrequency protection SAPTOF (81)

10.2.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Overfrequency protection	SAPTOF	f >	81

10.2.2 Application

Overfrequency protection function SAPTOF (81) is applicable in all situations, where reliable detection of high fundamental power system frequency is needed. The power system frequency, and rate of change of frequency, is a measure of the unbalance between the actual generation and the load demand. High fundamental frequency in a power system indicates that the available generation is too large compared to the power demanded by the load connected to the power grid. SAPTOF (81) detects such situations and provides an output signal, suitable for generator shedding, HVDC-set-point change and so on. SAPTOF (81) is very sensitive and accurate and can also be used to alert operators that frequency has slightly deviated from the set-point, and that manual actions might be enough.

10.2.3 Setting guidelines

All the frequency and voltage magnitude conditions in the system where SAPTOF (81) performs its functions must be considered. The same also applies to the associated equipment, its frequency and time characteristic.

There are two specific application areas for SAPTOF (81):

1. to protect equipment against damage due to high frequency, such as generators, and motors
2. to protect a power system, or a part of a power system, against breakdown, by shedding generation, in over production situations.

The overfrequency pickup value is set in Hz. All voltage magnitude related settings are made as a percentage of a settable global base voltage parameter *VBase*. The UBase value should be set as a primary phase-to-phase value.

Some applications and related setting guidelines for the frequency level are given below:

Equipment protection, such as for motors and generators

The setting has to be well above the highest occurring "normal" frequency and well below the highest acceptable frequency for the equipment.

Power system protection, by generator shedding

The setting must be above the highest occurring "normal" frequency and below the highest acceptable frequency for power stations, or sensitive loads. The setting level, the number of levels and the distance between two levels (in time and/or in frequency) depend very much on the characteristics of the power system under consideration. The size of the "largest loss of load" compared to "the size of the power system" is a critical parameter. In large systems, the generator shedding can be set at a fairly low frequency level, and the time delay is normally not critical. In smaller systems the frequency PICKUP level has to be set at a higher value, and the time delay must be rather short.

10.3 Rate-of-change frequency protection SAPFRC (81)

10.3.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Rate-of-change frequency protection	SAPFRC	$df/dt \gtrless$	81

10.3.2 Application

Rate-of-change frequency protection (SAPFRC, 81), is applicable in all situations, where reliable detection of change of the fundamental power system voltage frequency is needed. SAPFRC (81) can be used both for increasing frequency and for decreasing frequency. SAPFRC (81) provides an output signal, suitable for load shedding or generator shedding, generator boosting, HVDC-set-point change, gas turbine start up and so on. Very often SAPFRC (81) is used in combination with a low frequency signal, especially in smaller power systems, where loss of a fairly large generator will require quick remedial actions to secure the power system integrity. In such situations load shedding actions are required at a rather high frequency level, but in combination with a large negative rate-of-change of frequency the underfrequency protection can be used at a rather high setting.

10.3.3 Setting guidelines

The parameters for Rate-of-change frequency protection SAPFRC (81) are set via the local HMI or or through the Protection and Control Manager (PCM600).

All the frequency and voltage magnitude conditions in the system where SAPFRC (81) performs its functions should be considered. The same also applies to the associated equipment, its frequency and time characteristic.

There are two specific application areas for SAPFRC (81):

1. to protect equipment against damage due to high or too low frequency, such as generators, transformers, and motors
2. to protect a power system, or a part of a power system, against breakdown by shedding load or generation, in situations where load and generation are not in balance.

SAPFRC (81) is normally used together with an overfrequency or underfrequency function, in small power systems, where a single event can cause a large imbalance between load and generation. In such situations load or generation shedding has to take place very quickly, and there might not be enough time to wait until the frequency signal has reached an abnormal value. Actions are therefore taken at a frequency level closer to the primary nominal level, if the rate-of-change frequency is large (with respect to sign).

SAPFRC (81)PICKUP value is set in Hz/s. All voltage magnitude related settings are made as a percentage of a settable base voltage, which normally is set to the primary nominal voltage level (phase-phase) of the power system or the high voltage equipment under consideration.

SAPFRC (81) is not instantaneous, since the function needs some time to supply a stable value. It is recommended to have a time delay long enough to take care of signal noise. However, the time, rate-of-change frequency and frequency steps between different actions might be critical, and sometimes a rather short operation time is required, for example, down to 70 ms.

Smaller industrial systems might experience rate-of-change frequency as large as 5 Hz/s, due to a single event. Even large power systems may form small islands with a large imbalance between load and generation, when severe faults (or combinations of faults) are cleared - up to 3 Hz/s has been experienced when a small island was isolated from a large system. For more "normal" severe disturbances in large power systems, rate-of-change of frequency is much less, most often just a fraction of 1.0 Hz/s.

Section 11 Secondary system supervision

11.1 Fuse failure supervision SDDRFUF

11.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Fuse failure supervision	SDDRFUF	-	-

11.1.2 Application

Different protection functions within the protection IED, operates on the basis of the measured voltage in the relay point. Examples are:

- distance protection function
- under/over-voltage function
- synchronism check function and voltage check for the weak infeed logic.

These functions can operate unintentionally if a fault occurs in the secondary circuits between the voltage instrument transformers and the IED.

It is possible to use different measures to prevent such unwanted operations. Miniature circuit breakers in the voltage measuring circuits, located as close as possible to the voltage instrument transformers, are one of them. Separate fuse-failure monitoring IEDs or elements within the protection and monitoring devices are another possibilities. These solutions are combined to get the best possible effect in the fuse failure supervision function (SDDRFUF).

SDDRFUF function built into the IED products can operate on the basis of external binary signals from the miniature circuit breaker or from the line disconnector. The first case influences the operation of all voltage-dependent functions while the second one does not affect the impedance measuring functions.

The negative sequence detection algorithm, based on the negative-sequence measuring quantities, a high value of voltage $3V_2$ without the presence of the negative-sequence current $3I_2$, is recommended for use in isolated or high-impedance grounded networks.

The zero sequence detection algorithm, based on the zero sequence measuring quantities, a high value of voltage $3V_0$ without the presence of the residual current $3I_0$, is recommended for use in directly or low impedance grounded networks. In cases where the line can have a weak-infeed of zero sequence current this function shall be avoided.

A criterion based on delta current and delta voltage measurements can be added to the fuse failure supervision function in order to detect a three phase fuse failure. This is beneficial for example during three phase transformer switching.

11.1.3 Setting guidelines

11.1.3.1 General

The negative and zero sequence voltages and currents always exist due to different non-symmetries in the primary system and differences in the current and voltage instrument transformers. The minimum value for the operation of the current and voltage measuring elements must always be set with a safety margin of 10 to 20%, depending on the system operating conditions.

Pay special attention to the dissymmetry of the measuring quantities when the function is used on longer untransposed lines, on multicircuit lines and so on.

The settings of negative sequence, zero sequence and delta algorithm are in percent of the base voltage and base current for the function, *VBase* and *IBase* respectively. Set *VBase* to the primary rated phase-phase voltage of the potential voltage transformer and *IBase* to the primary rated current of the current transformer.

11.1.3.2 Setting of common parameters

GlobalBaseSel: Selects the global base value group used by the function to define (*IBase*), (*VBase*) and (*SBase*).

The settings of negative sequence, zero sequence and delta algorithm are in percent of the global base voltage and global base current for the function, *VBase* and *IBase* respectively.

The voltage threshold *VSealInPU* is used to identify low voltage condition in the system. Set *VSealInPU* below the minimum operating voltage that might occur during emergency conditions. We propose a setting of approximately 70% of the global parameter *VBase*.

The drop off time of 200 ms for dead phase detection makes it recommended to always set *SealIn* to *Enabled* since this will secure a fuse failure indication at persistent fuse fail when closing the local breaker when the line is already energized from the other

end. When the remote breaker closes the voltage will return except in the phase that has a persistent fuse fail. Since the local breaker is open there is no current and the dead phase indication will persist in the phase with the blown fuse. When the local breaker closes the current will start to flow and the function detects the fuse failure situation. But due to the 200 ms drop off timer the output BLKZ will not be activated until after 200 ms. This means that distance functions are not blocked and due to the "no voltage but current" situation might issue a trip.

The operation mode selector *OpModeSel* has been introduced for better adaptation to system requirements. The mode selector makes it possible to select interactions between the negative sequence and zero sequence algorithm. In normal applications the *OpModeSel* is set to either *V2I2* for selecting negative sequence algorithm or *V0I0* for zero sequence based algorithm. If system studies or field experiences shows that there is a risk that the fuse failure function will not be activated due to the system conditions, the dependability of the fuse failure function can be increased if the *OpModeSel* is set to *V0I0 OR V2I2* or *OptimZsNs*. In mode *V0I0 OR V2I2* both the negative and zero sequence based algorithm is activated and working in an OR-condition. Also in mode *OptimZsNs* both the negative and zero sequence algorithm are activated and the one that has the highest magnitude of measured negative sequence current will operate. If there is a requirement to increase the security of the fuse failure function *OpModeSel* can be selected to *V0I0 AND V2I2* which gives that both negative and zero sequence algorithm is activated working in an AND-condition, that is, both algorithm must give condition for block in order to activate the output signals BLKV or BLKZ.

11.1.3.3 Negative sequence based

The relay setting value *3V2PU* is given in percentage of the base voltage *VBase* and should not be set lower than according to equation 78.

$$3V2PU = \frac{3V2}{VBase} \cdot 100$$

(Equation 78)

where:

3V2PU	is maximal negative sequence voltage during normal operation condition
VBase	is setting of the global base voltage for all functions in the IED.

The setting of the current limit *3I2PU* is in percentage of global parameter *IBase*. The setting of *3I2PU* must be higher than the normal unbalance current that might exist in the system and can be calculated according to equation 79.

$$3I2PU = \frac{3I2}{IBase} \cdot 100$$

(Equation 79)

where:

3I2	is maximal negative sequence current during normal operating condition
IBase	is setting of base current for the function

11.1.3.4 Zero sequence based

The relay setting value *3V0PU* is given in percentage of the global parameter *VBase*. The setting of *3V0PU* should not be set lower than according to equation 80.

$$3V0PU = \frac{3V0}{VBase} \cdot 100$$

(Equation 80)

where:

3V0	is maximal zero sequence voltage during normal operation condition
VBase	is setting of global base voltage all functions in the IED.

The setting of the current limit *3I0PU* is done in percentage of the global parameter *IBase*. The setting of *3I0PU* must be higher than the normal unbalance current that might exist in the system. The setting can be calculated according to equation 81.

$$3I0PU = \frac{3I0}{IBase} \cdot 100$$

(Equation 81)

where:

3I0PU	is maximal zero sequence current during normal operating condition
IBase	is setting of global base current all functions in the IED.

11.1.3.5 Delta V and delta I

Set the operation mode selector *OpDVDI* to *Enabled* if the delta function shall be in operation.

The setting of *DVPU* should be set high (approximately 60% of *VBase*) and the current threshold *DIPU* low (approximately 10% of *IBase*) to avoid unwanted operation due to normal switching conditions in the network. The delta current and delta voltage function shall always be used together with either the negative or zero sequence algorithm. If *VSetprim* is the primary voltage for operation of dU/dt and *ISetprim* the primary current for operation of dI/dt, the setting of *DVPU* and *DIPU* will be given according to equation 82 and equation 83.

$$DVPU = \frac{VSetprim}{VBase} \cdot 100$$

(Equation 82)

$$DIPU = \frac{ISetprim}{IBase} \cdot 100$$

(Equation 83)

The voltage thresholds *VPPU* is used to identify low voltage condition in the system. Set *VPPU* below the minimum operating voltage that might occur during emergency conditions. We propose a setting of approximately 70% of *VB*.

The current threshold *50P* shall be set lower than the *IMinOp* for the distance protection function. A 5-10% lower value is recommended.

11.1.3.6 Dead line detection

The condition for operation of the dead line detection is set by the parameters *IDLDPU* for the current threshold and *VDLDPU* for the voltage threshold.

Set the *IDLDPU* with a sufficient margin below the minimum expected load current. A safety margin of at least 15-20% is recommended. The operate value must however exceed the maximum charging current of an overhead line, when only one phase is disconnected (mutual coupling to the other phases).

Set the *VDLDPU* with a sufficient margin below the minimum expected operating voltage. A safety margin of at least 15% is recommended.

11.2 Breaker close/trip circuit monitoring TCSSCBR

11.2.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Breaker close/trip circuit monitoring	TCSSCBR	-	-

11.2.2 Application

TCSSCBR detects faults in the electrical control circuit of the circuit breaker. The function can supervise both open and closed coil circuits. This kind of monitoring is necessary to find out the vitality of the control circuits continuously.

Trip circuit supervision generates a current of approximately 1.0 mA through the supervised circuit. It must be ensured that this current will not cause a latch up of the controlled object.

To protect the trip circuit supervision circuits in the IED, the output contacts are provided with parallel transient voltage suppressors. The breakdown voltage of these suppressors is 400 +/– 20 V DC.

The following figure shows an application of the trip-circuit monitoring function usage. The best solution is to connect an external R_{ext} shunt resistor in parallel with the circuit breaker internal contact. Although the circuit breaker internal contact is open, TCSSCBR can see the trip circuit through R_{ext}. The R_{ext} resistor should have such a resistance that the current through the resistance remains small, that is, it does not harm or overload the circuit breaker's trip coil.

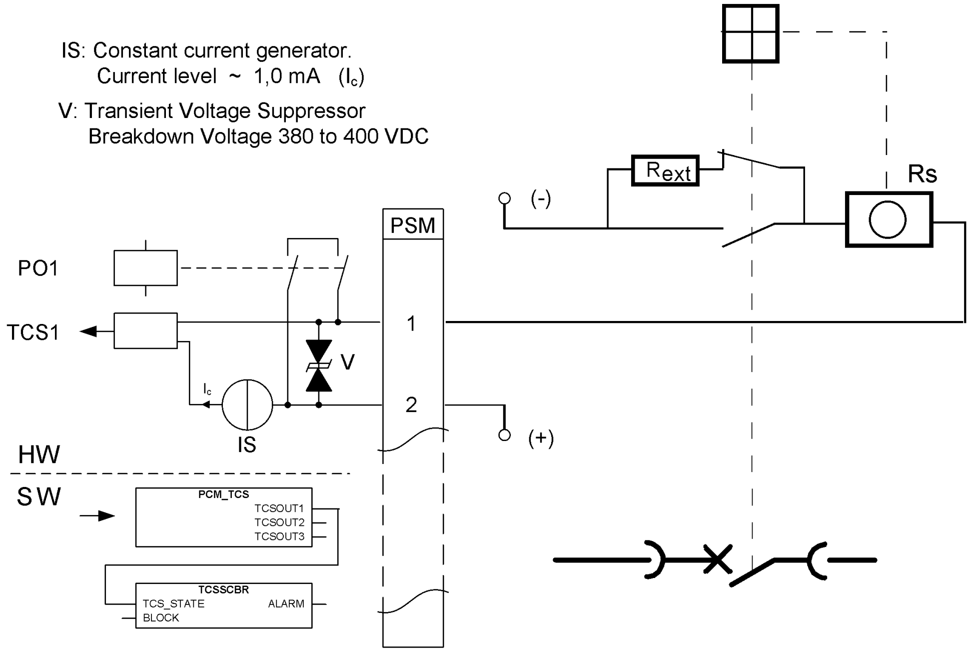


Figure 95: Operating principle of the trip-circuit supervision with an external resistor. The TCSSCBR blocking switch is not required since the external resistor is used.

If the TCSSCBR is required only in a closed position, the external shunt resistance may be omitted. When the circuit breaker is in the open position, the TCSSCBR sees the situation as a faulty circuit. One way to avoid TCSSCBR operation in this situation would be to block the monitoring function whenever the circuit breaker is open.

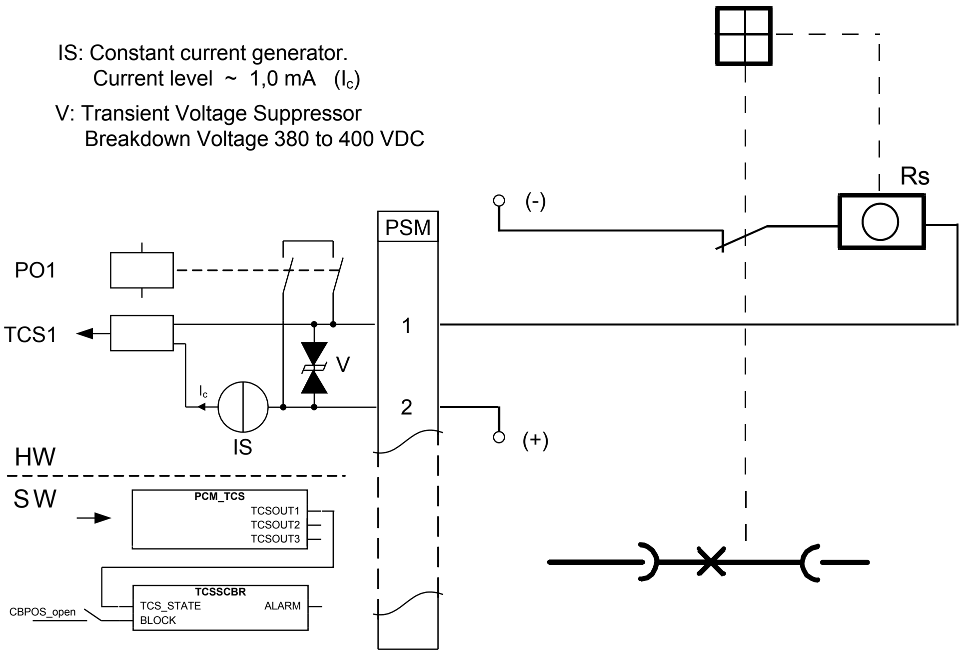


Figure 96: Operating principle of the trip-circuit supervision without an external resistor. The circuit breaker open indication is set to block TCSSCBR when the circuit breaker is open.

Trip-circuit monitoring and other trip contacts

It is typical that the trip circuit contains more than one trip contact in parallel, for example in transformer feeders where the trip of a Buchholz relay is connected in parallel with the feeder terminal and other relays involved.

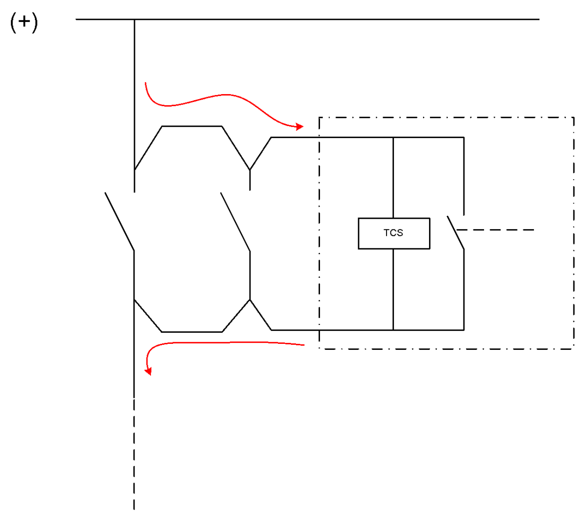


Figure 97: Constant test current flow in parallel trip contacts and trip-circuit supervision

Several trip-circuit monitoring functions parallel in circuit

Not only the trip circuit often have parallel trip contacts, it is also possible that the circuit has multiple TCSSCBR circuits in parallel. Each TCSSCBR circuit causes its own supervising current to flow through the monitored coil and the actual coil current is a sum of all TCSSCBR currents. This must be taken into consideration when determining the resistance of R_{ext}.

Setting the TCSSCBR function in a protection IED not-in-use does not typically affect the supervising current injection.

Trip-circuit monitoring with auxiliary relays

Many retrofit projects are carried out partially, that is, the old electromechanical relays are replaced with new ones but the circuit breaker is not replaced. This creates a problem that the coil current of an old type circuit breaker can be too high for the protection IED trip contact to break.

The circuit breaker coil current is normally cut by an internal contact of the circuit breaker. In case of a circuit breaker failure, there is a risk that the protection IED trip contact is destroyed since the contact is obliged to disconnect high level of electromagnetic energy accumulated in the trip coil.

An auxiliary relay can be used between the protection IED trip contact and the circuit breaker coil. This way the breaking capacity question is solved, but the TCSSCBR

circuit in the protection IED monitors the healthy auxiliary relay coil, not the circuit breaker coil. The separate trip circuit monitoring relay is applicable for this to supervise the trip coil of the circuit breaker.

Dimensioning of the external resistor

Under normal operating conditions, the applied external voltage is divided between the relay’s internal circuit and the external trip circuit so that at the minimum 10 V (3...10 V) remains over the relay’s internal circuit. Should the external circuit’s resistance be too high or the internal circuit’s too low, for example due to welded relay contacts, the fault is detected.

Mathematically, the operation condition can be expressed as:

$$V_c - (R_{ext} + R_s) \times I_c \geq 10V\ DC$$

(Equation 84)

V_c	Operating voltage over the supervised trip circuit
I_c	Measuring current through the trip circuit, appr. 1.0 mA (0.85...1.20 mA)
R_{ext}	external shunt resistance
R_s	trip coil resistance

If the external shunt resistance is used, it has to be calculated not to interfere with the functionality of the supervision or the trip coil. Too high a resistance causes too high a voltage drop, jeopardizing the requirement of at least 20 V over the internal circuit, while a resistance too low can enable false operations of the trip coil.

Table 28: Values recommended for the external resistor R_{ext}

Operating voltage U_c	Shunt resistor R_{ext}
48 V DC	10 kΩ, 5 W
60 V DC	22 kΩ, 5 W
110 V DC	33 kΩ, 5 W
220 V DC	68 kΩ, 5 W

Due to the requirement that the voltage over the TCSSCBR contact must be 20V or higher, the correct operation is not guaranteed with auxiliary operating voltages lower than 48V DC because of the voltage drop in the R_{ext} and operating coil or even voltage drop of the feeding auxiliary voltage system which can cause too low voltage values over the TCSSCBR contact. In this case, erroneous alarming can occur.

At lower (<48V DC) auxiliary circuit operating voltages, it is recommended to use the circuit breaker position to block unintentional operation of TCSSCBR. The use of the position indication is described earlier in this chapter.

Section 12 Control

12.1 Synchronism check, energizing check, and synchronizing SESRSYN (25)

12.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Synchrocheck, energizing check, and synchronizing	SESRSYN	sc/vc	25

12.1.2 Application

12.1.2.1 Synchronizing

To allow closing of breakers between asynchronous networks a synchronizing function is provided. The breaker close command is issued at the optimum time when conditions across the breaker are satisfied in order to avoid stress on the network and its components.

The systems are defined to be asynchronous when the frequency difference between bus and line is larger than an adjustable parameter. If the frequency difference is less than this threshold value the system is defined to have a parallel circuit and the synchronism check function is used.

The synchronizing function measures the difference between the V-Line and the V-Bus. It operates and enables a closing command to the circuit breaker when the calculated closing angle is equal to the measured phase angle and the following conditions are simultaneously fulfilled:

- The voltage V-Line is higher than 80% of *GblBaseSelLine* and the voltage V-Bus is higher than 80% of *GblBaseSelBus*.
- The voltage difference is smaller than 0.10 p.u, that is (V-Bus/*GblBaseSelBus*) - (V-Line/*GblBaseSelLine*) < 0.10.
- The difference in frequency is less than the set value of *FreqDiffMax* and larger than the set value of *FreqDiffMin*. If the frequency is less than *FreqDiffMin* the synchronism check is used and the value of *FreqDiffMin* must thus be identical to the value *FreqDiffM* resp *FreqDiffA* for synchronism check function. The bus and line frequencies must also be within a range of +/- 5 Hz from the rated frequency. When the synchronizing option is included also for autoreclose there is no reason to have different frequency setting for the manual and automatic reclosing and the frequency difference values for synchronism check should be kept low.
- The frequency rate of change is less than set value for both V-Bus and V-Line.
- The closing angle is decided by the calculation of slip frequency and required pre-closing time.

The synchronizing function compensates for measured slip frequency as well as the circuit breaker closing delay. The phase advance is calculated continuously. Closing angle is the change in angle during the set breaker closing operate time *tBreaker*.

The reference voltage can be phase-neutral A, B, C or phase-phase A-B, B-C, C-A or positive sequence. The bus voltage must then be connected to the same phase or phases as are chosen for the line or a compensation angle set to compensate for the difference.

12.1.2.2 Synchronism check

The main purpose of the synchronism check function is to provide control over the closing of circuit breakers in power networks in order to prevent closing if conditions for synchronism are not detected. It is also used to prevent the re-connection of two systems, which are divided after islanding and after a three pole reclosing.

Single pole auto-reclosing does not require any synchronism check since the system is tied together by two phases.

SESRSYN (25) function block includes both the synchronism check function and the energizing function to allow closing when one side of the breaker is dead. SESRSYN (25) function also includes a built in voltage selection scheme which allows simple application in busbar arrangements.

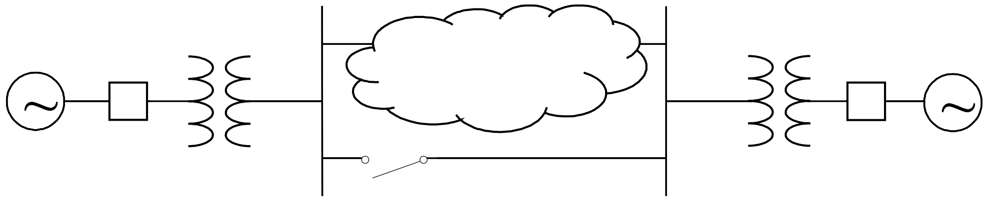


Figure 98: Two interconnected power systems

Figure 98 shows two interconnected power systems. The cloud means that the interconnection can be further away, that is, a weak connection through other stations. The need for a check of synchronization increases as the meshed system decreases since the risk of the two networks being out of synchronization at manual or automatic closing is greater.

The synchronism check function measures the conditions across the circuit breaker and compares them to set limits. Output is generated only when all measured conditions are within their set limits simultaneously. The check consists of:

- Live line and live bus.
- Voltage level difference.
- Frequency difference (slip). The bus and line frequency must also be within a range of ±5 Hz from rated frequency.
- Phase angle difference.

A time delay is available to ensure that the conditions are fulfilled for a minimum period of time.

In very stable power systems the frequency difference is insignificant or zero for manually initiated closing or closing by automatic restoration. In steady conditions a bigger phase angle difference can be allowed as this is sometimes the case in a long and loaded parallel power line. For this application we accept a synchronism check with a long operation time and high sensitivity regarding the frequency difference. The phase angle difference setting can be set for steady state conditions.

Another example, is when the operation of the power net is disturbed and high-speed auto-reclosing after fault clearance takes place. This can cause a power swing in the net and the phase angle difference may begin to oscillate. Generally, the frequency difference is the time derivative of the phase angle difference and will, typically oscillate between positive and negative values. When the circuit breaker needs to be closed by auto-reclosing after fault-clearance some frequency difference should be tolerated, to a greater extent than in the steady condition mentioned in the case above. But if a big phase angle difference is allowed at the same time, there is some risk that

auto-reclosing will take place when the phase angle difference is big and increasing. In this case it should be safer to close when the phase angle difference is smaller.

To fulfill the above requirements the synchronism check function is provided with duplicate settings, one for steady (Manual) conditions and one for operation under disturbed conditions (Auto).

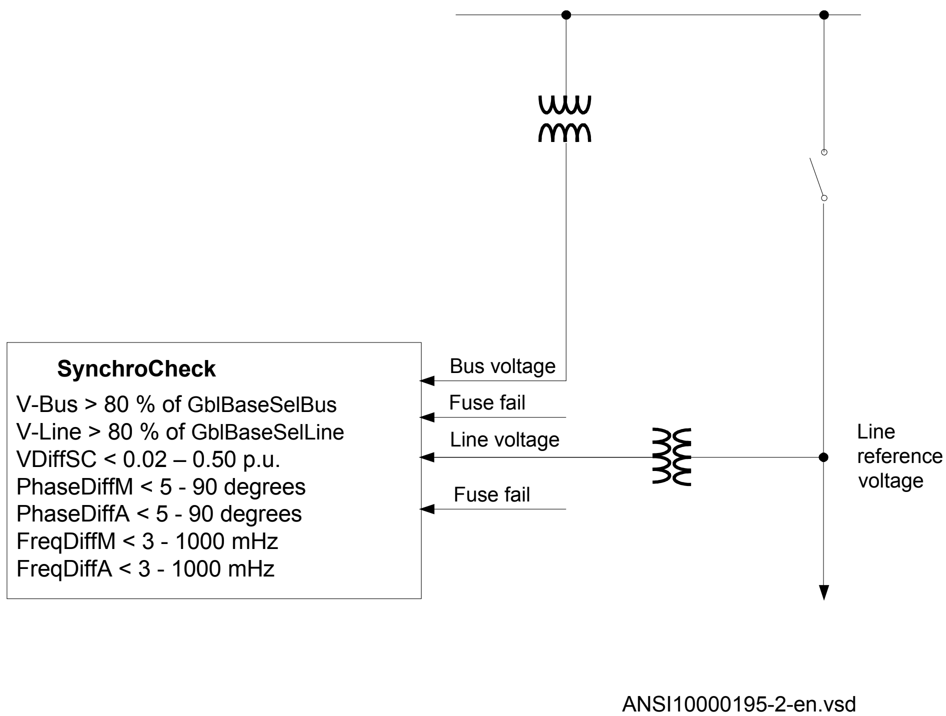


Figure 99: Principle for the synchronism check function

12.1.2.3 Energizing check

The main purpose of the energizing check function is to facilitate the controlled re-connection of disconnected lines and buses to energized lines and buses.

The energizing check function measures the bus and line voltages and compares them to both high and low threshold values. The output is given only when the actual measured conditions match the set conditions. Figure 100 shows two power systems, where one (1) is energized and the other (2) is not energized. Power system 2 is energized (DLLB) from system 1 via the circuit breaker A.

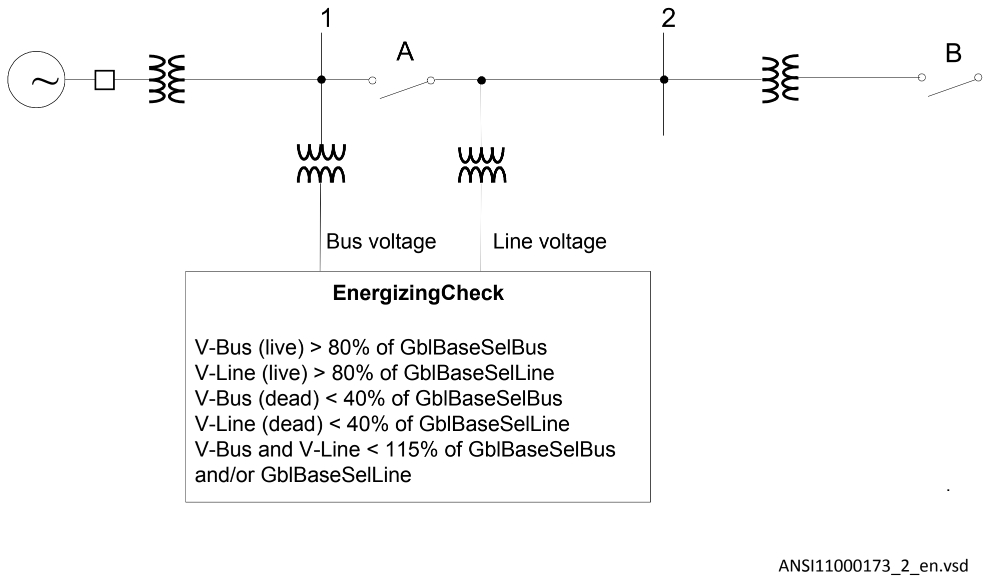


Figure 100: Principle for the energizing check function

The energizing operation can operate in the dead line live bus (DLLB) direction, dead bus live line (DBLL) direction, or in both directions over the circuit breaker. Energizing from different directions can be different for automatic reclosing and manual closing of the circuit breaker. For manual closing it is also possible to allow closing when both sides of the breaker are dead, Dead Bus Dead Line (DBDL).

The equipment is considered energized if the voltage is above set value of *UHighBusEnerg* or *UHighLineEnerg* of the base voltage, and non-energized if it is below set value of *ULowBusEnerg* or *ULowLineEnerg* of the base voltage. A disconnected line can have a considerable potential because of factors such as induction from a line running in parallel, or feeding via extinguishing capacitors in the circuit breakers. This voltage can be as high as 50% or more of the base voltage of the line. Normally, for breakers with single breaking elements (<330kV) the level is well below 30%.

When the energizing direction corresponds to the settings, the situation has to remain constant for a certain period of time before the close signal is permitted. The purpose of the delayed operate time is to ensure that the dead side remains de-energized and that the condition is not due to temporary interference.

12.1.2.4 Voltage selection

The voltage selection function is used for the connection of appropriate voltages to the synchronism check and energizing check functions. For example, when the IED is used

in a double bus arrangement, the voltage that should be selected depends on the status of the breakers and/or disconnectors. By checking the status of the disconnectors auxiliary contacts, the right voltages for the synchronism check and energizing check functions can be selected.

Available voltage selection types are for single circuit breaker with double busbars and the breaker-and-a-half arrangement. A double circuit breaker arrangement and single circuit breaker with a single busbar do not need any voltage selection function. Neither does a single circuit breaker with double busbars using external voltage selection need any internal voltage selection.

The voltages from busbars and lines must be physically connected to the voltage inputs in the IED and connected, using the control software, to each of the SESRSYN (25) functions available in the IED.

12.1.2.5 External fuse failure

External fuse-failure signals or signals from a tripped fuse switch/MCB are connected to binary inputs that are configured to inputs of SESRSYN (25) function in the IED. The internal fuse failure supervision function can also be used, for at least the line voltage supply. The signal BLKU, from the internal fuse failure supervision function, is then used and connected to the blocking input of the energizing check function block. In case of a fuse failure, the SESRSYN (25) function is blocked.

The VB1OK/VB2OK and VB1FF/VB2FF inputs are related to the busbar voltage and the VL1OK/VL2OK and VL1FF/VL2FF inputs are related to the line voltage.

External selection of energizing direction

The energizing can be selected by use of the available logic function blocks. Below is an example where the choice of mode is done from a symbol on the local HMI through selector switch function block, but alternatively there can for example, be a physical selector switch on the front of the panel which is connected to a binary to integer function block (B16I).

If the PSTO input is used, connected to the Local-Remote switch on the local HMI, the choice can also be from the station HMI system, typically ABB Microscada through IEC 61850–8–1 communication.

The connection example for selection of the manual energizing mode is shown in figure 101. Selected names are just examples but note that the symbol on the local HMI can only show three signs.

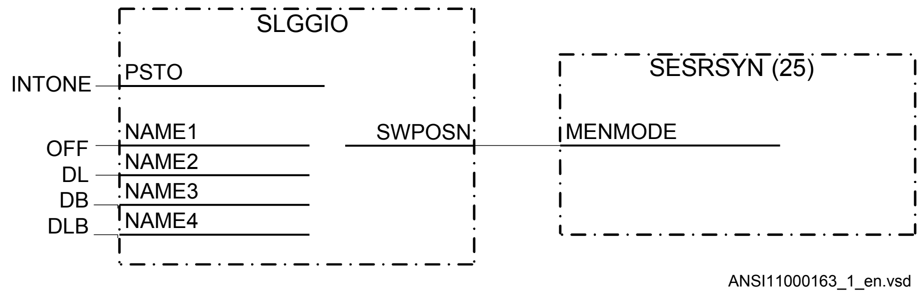


Figure 101: Selection of the energizing direction from a local HMI symbol through a selector switch function block.

12.1.3 Application examples

SESRSYN (25) function block can also be used in some switchyard arrangements, but with different parameter settings. Below are some examples of how different arrangements are connected to the IED analog inputs and to the function block SESRSYN(25).

The input used below in example are typical and can be changed by use of configuration and signal matrix tools.

The SESRSYN and connected SMAI function block instances must have the same cycle time in the application configuration.

12.1.3.1 Single circuit breaker with single busbar

Figure "" illustrates connection principles. For the SESRSYN (25) function there is one voltage transformer on each side of the circuit breaker. The voltage transformer circuit connections are straightforward; no special voltage selection is necessary.

The voltage from busbar VT is connected to V3PB1 and the voltage from the line VT is connected to V3PL1. The positions of the VT fuses shall also be connected as shown above. The voltage selection parameter *CBConfig* is set to *No voltage sel*.

12.1.3.2 Single circuit breaker with double busbar, external voltage selection

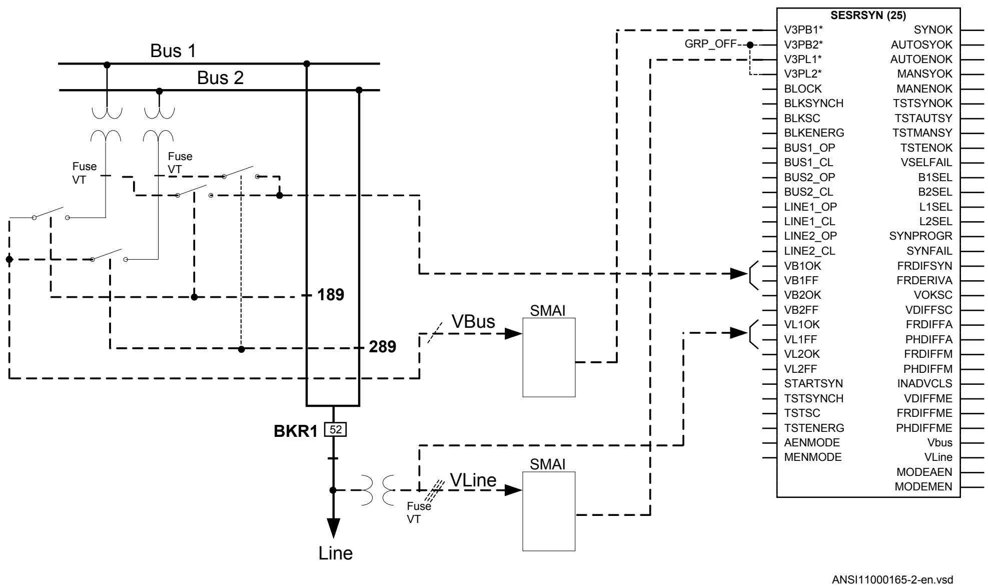


Figure 102: Connection of SESRSYN (25) function block in a single breaker, double busbar arrangement with external voltage selection

In this type of arrangement no internal voltage selection is required. The voltage selection is made by external relays typically connected according to figure 102. Suitable voltage and VT fuse failure supervision from the two busbars are selected based on the position of the busbar disconnectors. This means that the connections to the function block will be the same as for the single busbar arrangement. The voltage selection parameter *CBConfig* is set to *No voltage sel*.

12.1.3.3 Single circuit breaker with double busbar, internal voltage selection

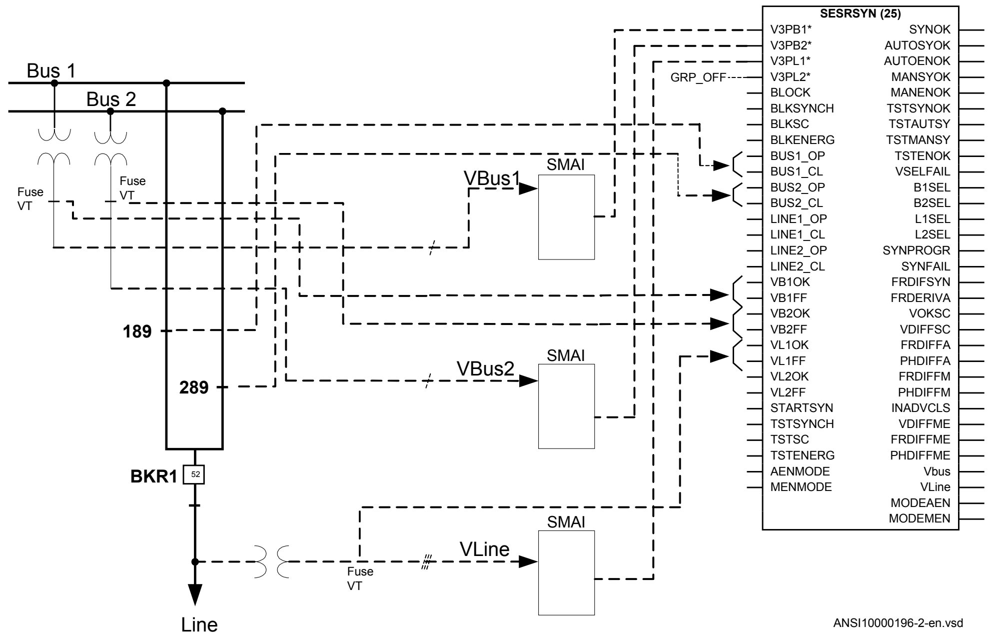


Figure 103: Connection of the SESRSYN (25) function block in a single breaker, double busbar arrangement with internal voltage selection.

When internal voltage selection is needed, the voltage transformer circuit connections are made according to figure 103. The voltage from busbar1 VT is connected to V3PB1 and the voltage from busbar2 VT is connected to V3PB2. The voltage from the line VT is connected to V3PL1. The positions of the disconnectors and VT fuses shall be connected as shown in figure 103. The voltage selection parameter *CBConfig* is set to *Double bus*.

12.1.3.4 Double circuit breaker

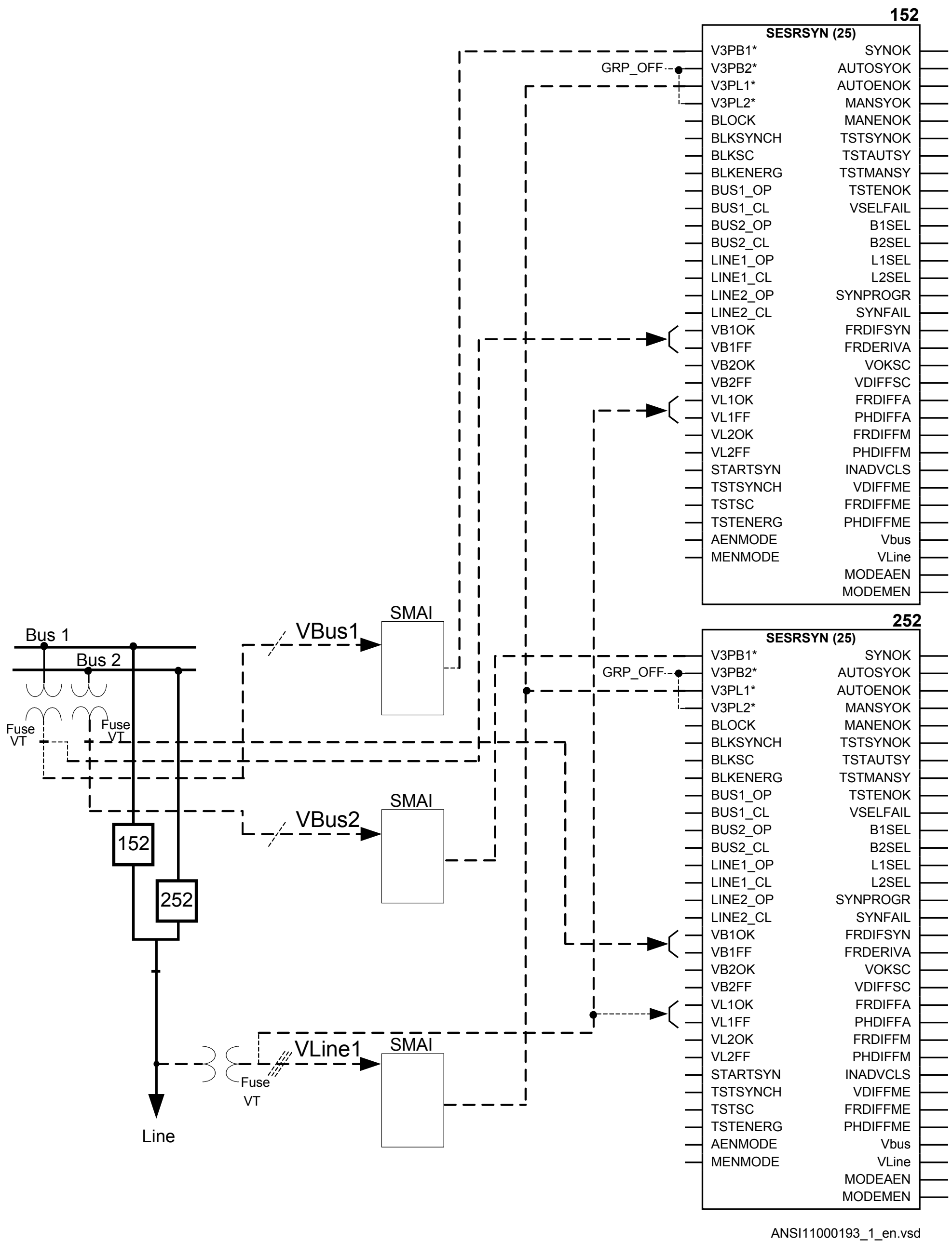


Figure 104: Connections of the SESRSYN (25) function block in a double breaker arrangement

A double breaker arrangement requires two function blocks, SESRSYN1 for breaker QA1 and SESRSYN2 for breaker QA2. No voltage selection is necessary, because the

voltage from busbar1 VT is connected to V3PB1 on SESRSYN1 and the voltage from busbar2 VT is connected to V3PB1 on SESRSYN2. The voltage from the line VT is connected to V3PL1 on both SESRSYN1 and SESRSYN2. The condition of VT fuses shall also be connected as shown in figure 104. The voltage selection parameter *CBConfig* is set to *No voltage sel.* for both SESRSYN1 and SESRSYN2.

12.1.3.5 Breaker-and-a-half

The line one IED in a breaker-and-a-half arrangement handles voltage selection for busbar1 CB and for the tie CB. The IED requires two function blocks, SESRSYN1 for busbar1 CB and SESRSYN2 for the tie CB. The voltage from busbar1 VT is connected to V3PB1 on both function blocks and the voltage from busbar2 VT is connected to V3PB2 on both function blocks. The voltage from line1 VT is connected to V3PL1 on both function blocks and the voltage from line2 VT is connected to V3PL2 on both function blocks. The positions of the disconnectors and VT fuses shall be connected as shown in figure 105.

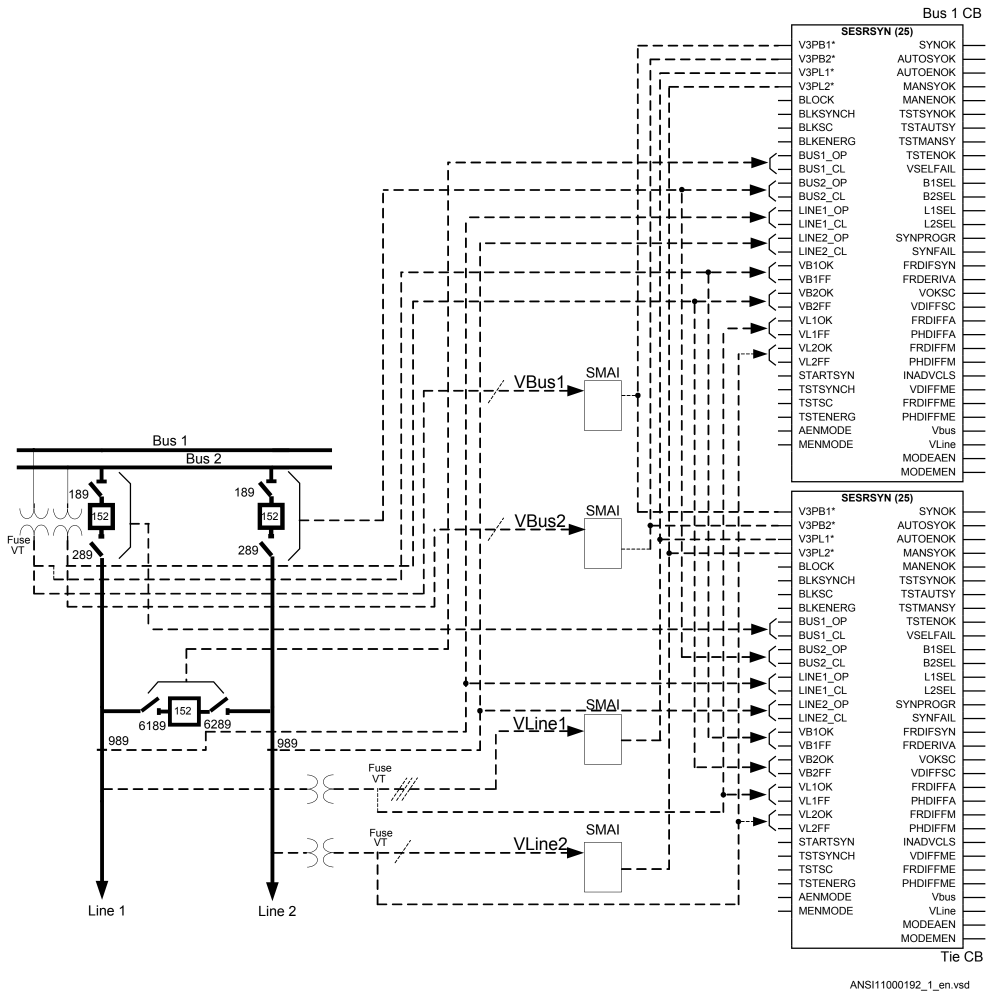


Figure 105: Connections of the SESRSYN (25) function block in a breaker-and-a-half arrangement with internal voltage selection for the line 1 IED

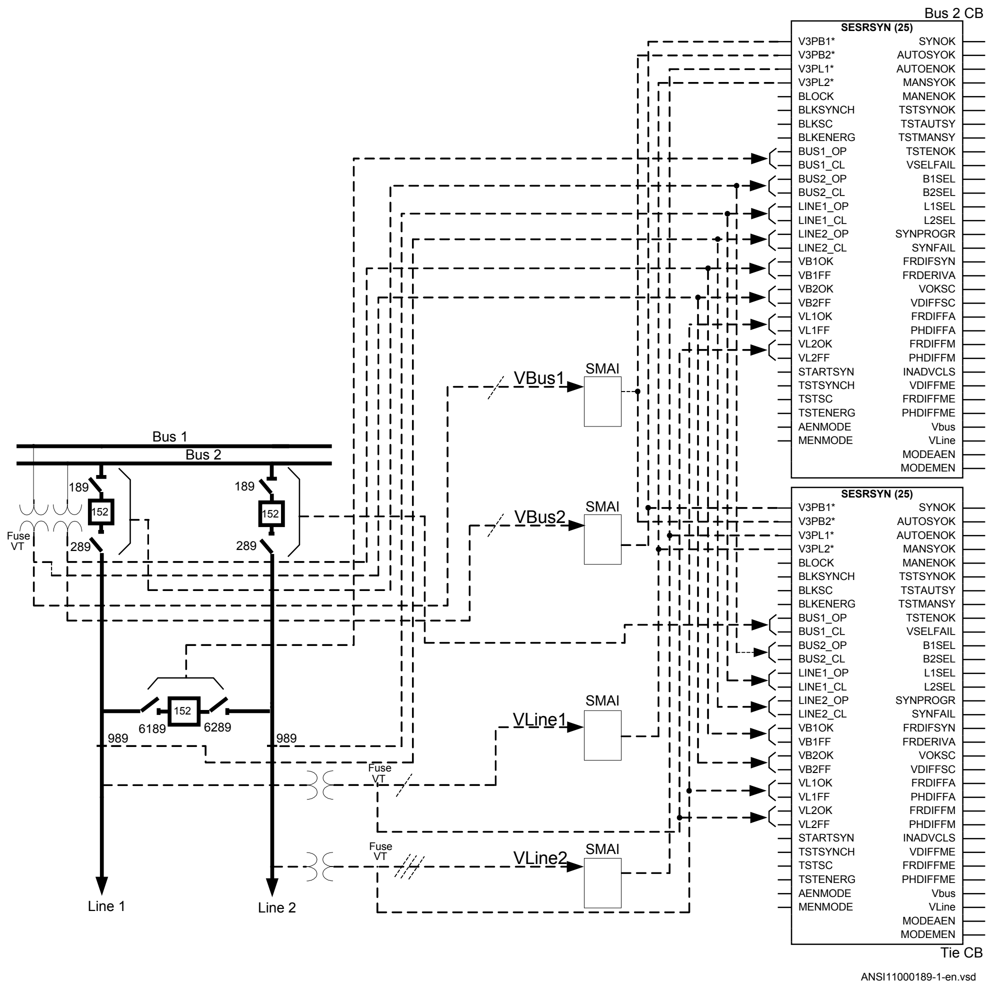


Figure 106: Connections of the SESRSYN (25) function block in a breaker-and-a-half arrangement with internal voltage selection for the line 2 IED

The example shows the use of the SESRSYN function for the Tie Circuit breaker in both Line IEDs. This depends on the arrangement of Auto-reclose and manual closing and might often not be required.

The connections are similar in both IEDs, apart from the live voltages and bus voltages, which are crossed. The line two IED in a breaker-and-a-half arrangement handles voltage selection for busbar2 CB and for the tie CB. The IED requires two function blocks, SESRSYN1 for busbar2 CB and SESRSYN2 for the tie CB. The voltage from busbar1 VT is connected to V3PB2 on both function blocks and the voltage from busbar2 VT is connected to V3PB1 on both function blocks. The voltage

from line1 VT is connected to V3PL2 on both function blocks and the voltage from line2 VT is connected to V3PL1 on both function blocks. Also, crossed positions of the disconnectors and VT fuses shall be connected as shown in figure 106. The physical analog connections of voltages and the connection to the IED and SESRSYN (25) function blocks must be carefully checked in PCM600. In both IEDs the connections and configurations must abide by the following rules: Normally apparatus position is connected with contacts showing both open (b-type) and closed positions (a-type).

Bus CB:

- BUS1_OP/CL = Position of the tie CB and disconnectors
- BUS2_OP/CL = Position of opposite bus CB and disconnectors
- LINE1_OP/CL = Position of own line disconnector
- LINE2_OP/CL = Position of opposite line disconnector
- VB1OK/FF = Supervision of bus VT fuse connected to own bus CB
- VB2OK/FF = Supervision of bus VT fuse connected to opposite bus CB
- VL1OK/FF = Supervision of line VT fuse connected to own line
- VL2OK/FF = Supervision of line VT fuse connected to opposite line
- Setting *CBConfig = 1 1/2 bus CB*

Tie CB:

- BUS1_OP/CL = Position of own bus CB and disconnectors
- BUS2_OP/CL = Position of opposite bus CB and disconnectors
- LINE1_OP/CL = Position of own line disconnector
- LINE2_OP/CL = Position of opposite line disconnector
- VB1OK/FF = Supervision of bus VT fuse connected to own bus CB
- VB2OK/FF = Supervision of bus VT fuse connected to opposite bus CB
- VL1OK/FF = Supervision of line VT fuse connected to own line
- VL2OK/FF = Supervision of line VT fuse connected to opposite line
- Setting *CBConfig = Tie CB*

If three SESRSYN (25) functions are provided in the same IED, or if preferred for other reason, the system can be set-up without “mirroring” by setting *CBConfig* to *1½ bus alt. CB* on the SESRSYN (25) function for the second busbar CB. Above standard is used because normally two SESRSYN (25) functions with the same configuration and settings are provided in a station for each bay.

12.1.4 Setting guidelines

The setting parameters for the Synchronizing, synchronism check and energizing check function SESRSYN (25) are set via the local HMI (LHMI) or PCM600.

This setting guidelines describes the settings of the SESRSYN (25) function via the LHMI.

Common base IED value for primary voltage (*VBase*) is set in a Global base value function, GBASVAL, found under **Main menu/Configuration/Power system/Global base values/X:GBASVAL/VBase**. GBASVAL has six instances which can be set independently of each other. The SESRSYN (25) function has one setting for the bus reference voltage (*GblBaseSelBus*) and one setting for the line reference voltage (*GblBaseSelLine*) which independently of each other can be set to select one of the six GBASVAL functions used for reference of base values. This means that the reference voltage of bus and line can be set to different values. The settings for the SESRSYN (25) function found under **Main menu/Settings/Control/SESRCYN(25,SYNC)/ X:SESRSYN** has been divided into four different setting groups: General, Synchronizing, Synchrocheck and Energizing check.

General settings

Operation: The operation mode can be set *Enabled* or *Disabled*. The setting *Disabled* disables the whole function.

GblBaseSelBus and *GblBaseSelLine*

These configuration settings are used for selecting one of six GBASVAL functions, which then is used as base value reference voltage, for bus and line respectively.

SelPhaseBus1 and *SelPhaseBus2*

Configuration parameters for selection of measuring phase of the voltage for the busbar 1 and 2 respectively, which can be a single-phase (phase-neutral) or two-phase (phase-phase) voltage.

SelPhaseLine1 and *SelPhaseLine2*

Configuration parameters for selection of measuring phase of the voltage for line 1 and 2 respectively, which can be a single-phase (phase-neutral) or two-phase (phase-phase) voltage or positive sequence.

CBConfig

This configuration setting is used to define type of voltage selection. Type of voltage selection can be selected as:

- no voltage selection
- single circuit breaker with double bus
- breaker-and-a-half arrangement with the breaker connected to busbar 1
- breaker-and-a-half arrangement with the breaker connected to busbar 2
- breaker-and-a-half arrangement with the breaker connected to line 1 and 2 (tie breaker)

VRatio

The *VRatio* is defined as *VRatio* = *bus voltage/line voltage*. This setting scales up the line voltage to an equal level with the bus voltage.

PhaseShift

This setting is used to compensate for a phase shift caused by a line transformer between the two measurement points for bus voltage and line voltage. The set value is added to the measured line phase angle. The bus voltage is reference voltage.

If single phase UL1 or two-phase UL1L2 is not available, parameters *PhaseShift* and *URatio* can be used to compensate for other choices.

Table 29: Voltage settings examples

Line voltage	Bus voltage	Bus voltage pre-processing	SESRSYN setting	
			PhaseShift	URatio
UL1	UL1	Connect UL1 to channel 1	-	1
	UL2	Connect UL2 to channel 1	- 120°	1
	UL3	Connect UL3 to channel 1	+ 120°	1
UL1L2	UL1L2	Connect UL1L2 to channel 1	-	1
	UL2L3	Connect UL2L3 to channel 1	- 120°	1
	UL3L1	Connect UL3L1 to channel 1	+ 120°	1
UL1	UL1L2	Connect UL1L2 to channel 1	- 30°	1.73
	UL2L3	Connect UL2L3 to channel 1	- 90°	1.73
	UL3L1	Connect UL3L1 to channel 1	+150°	1.73

Synchronizing settings

OperationSynch

The setting *Disabled* disables the Synchronizing function. With the setting *Enabled*, the function is in service and the output signal depends on the input conditions.

FreqDiffMin

The setting *FreqDiffMin* is the minimum frequency difference where the system are defined to be asynchronous. For frequency difference lower than this value the systems are considered to be in parallel. A typical value for the *FreqDiffMin* is *10* mHz. Generally, the value should be low if both, synchronizing and synchrocheck function is provided as it is better to let synchronizing function close as it will close at the exact right instance if the networks run with a frequency difference.

Note! The *FreqDiffMin* shall be set to the same value as *FreqDiffM* respective *FreqDiffA* for SESRSYN (25)dependent of whether the functions are used for manual operation, autoreclosing or both.

FreqDiffMax

The setting *FreqDiffMax* is the maximum slip frequency at which synchronizing is accepted. 1/*FreqDiffMax* shows the time for the vector to move 360 degrees, one turn on the synchronoscope and is called the Beat time A typical value for the *FreqDiffMax* is 200-250 mHz which gives beat times on 4-5 seconds. Higher values should be avoided as the two networks normally are regulated to nominal frequency independent of each other so the frequency difference shall be small.

FreqRateChange

The maximum allowed rate of change for the frequency.

tBreaker

The *tBreaker* shall be set to match the closing time for the circuit breaker and should also include the possible auxiliary relays in the closing circuit. It is important to check that no slow logic components are used in the configuration of the IED as there then can be big variations in closing time due to those components. Typical setting is *80-150* ms depending on the breaker closing time.

tClosePulse

Setting for the duration of the breaker close pulse.

tMaxSynch

The *tMaxSynch* is set to reset the operation of the synchronizing function if the operation does not take place within this time. The setting must allow for the setting of *FreqDiffMin*, which will decide how long it will take maximum to reach phase equality. At a setting of 10 ms the beat time is 100 seconds and the setting would thus need to be at least *tMinSynch* plus 100 seconds. If the network frequencies are expected to be outside the limits from start a margin needs to be added. Typical setting 600 seconds.

tMinSynch

The *tMinSynch* is set to limit the minimum time at which synchronizing closing attempt is given. The synchronizing function will not give a closing command within this time, from when the synchronizing is started, even if a synchronizing condition is fulfilled. Typical setting is *200* ms.

Synchrocheck settings

OperationSC

The *OperationSC* setting *Off* disables thesynchronsim check function and sets the outputs AUTOSYOK, MANSYOK, TSTAUTSY and TSTMANSY to low.

With the setting *Enabled*, the function is in service and the output signal depends on the input conditions.

VDiffSC

Setting for voltage difference between line and bus in p.u. This setting in p.u is defined as (V-Bus/*GblBaseSelBus*) - (V-Line/*GblBaseSelLine*).

FreqDiffM and *FreqDiffA*

The frequency difference level settings, *FreqDiffM* and *FreqDiffA*, shall be chosen depending on the condition in the network. At steady conditions a low frequency difference setting is needed, where the *FreqDiffM* setting is used. For auto-reclosing a bigger frequency difference setting is preferable, where the *FreqDiffA* setting is used. A typical value for the *FreqDiffM* can *10* mHz and a typical value for the *FreqDiffA* can be *100-200* mHz.

PhaseDiffM and *PhaseDiffA*

The phase angle difference level settings, *PhaseDiffM* and *PhaseDiffA*, shall also be chosen depending on conditions in the network. The phase angle setting must be chosen to allow closing under maximum load condition. A typical maximum value in heavy loaded networks can be *45* degrees whereas in most networks the maximum occurring angle is below *25* degrees.

tSCM and *tSCA*

The purpose of the timer delay settings, *tSCM* and *tSCA*, is to ensure that the synchronism check conditions remains constant and that the situation is not due to a temporary interference. Should the conditions not persist for the specified time, the delay timer is reset and the procedure is restarted when the conditions are fulfilled again. Circuit breaker closing is thus not permitted until the synchronism check situation has remained constant throughout the set delay setting time. Under stable conditions a longer operation time delay setting is needed, where the *tSCM* setting is used. During auto-reclosing a shorter operation time delay setting is preferable, where the *tSCA* setting is used. A typical value for the *tSCM* may be *1* second and a typical value for the *tSCA* may be *0.1* second.

Energizing check settings

AutoEnerg and *ManEnerg*

Two different settings can be used for automatic and manual closing of the circuit breaker. The settings for each of them are:

- *Disabled*, the energizing function is disabled.
- *DLLB*, Dead Line Live Bus, the line voltage is below a preset value of 40% of *GblBaseSelLine* and the bus voltage is above a preset value of 80% of *GblBaseSelBus*.
- *DBLL*, Dead Bus Live Line, the bus voltage is below a preset value of 40% of *GblBaseSelBus* and the line voltage is above a preset value of 80% of *GblBaseSelLine*.
- *Both*, energizing can be done in both directions, *DLLB* or *DBLL*.

ManEnergDBDL

If the parameter is set to *Enabled*, manual closing is enabled when line voltage is below a preset value of 40% of *GblBaseSelLine* and when bus voltage is below a preset value of 40% of *GblBaseSelBus* and also *ManEnerg* is set to *DLLB*, *DBLL* or *Both*.

tAutoEnerg and *tManEnerg*

The purpose of the timer delay settings, *tAutoEnerg* and *tManEnerg*, is to ensure that the dead side remains de-energized and that the condition is not due to a temporary interference. Should the conditions not persist for the specified time, the delay timer is reset and the procedure is restarted when the conditions are fulfilled again. Circuit breaker closing is thus not permitted until the energizing condition has remained constant throughout the set delay setting time.

12.2 Apparatus control

12.2.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Bay control	QCBAY	-	-
Local remote	LOCREM	-	-
Local remote control	LOCREMCTRL	-	-

12.2.2 Application

The apparatus control is a function for control and supervising of circuit breakers, disconnectors, and grounding switches within a bay. Permission to operate is given after evaluation of conditions from other functions such as interlocking, synchronism check, operator place selection and external or internal blockings.

The complete apparatus control function is not included in this product, and the information below is included for understanding of the principle for the use of QCBAY, LOCREM, and LOCREMCTRL for the selection of the operator place.

Figure 107 gives an overview from what places the apparatus control function receive commands. Commands to an apparatus can be initiated from the Control Centre (CC), the station HMI or the local HMI on the IED front.

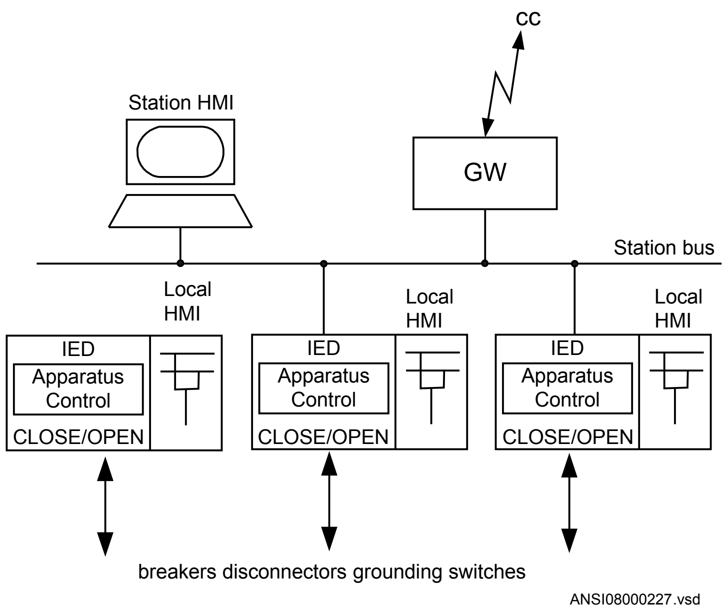


Figure 107: Overview of the apparatus control functions

Features in the apparatus control function:

- Operation of primary apparatuses
- Select-Execute principle to give high security
- Selection function to prevent simultaneous operation
- Selection and supervision of operator place
- Command supervision
- Block/deblock of operation
- Block/deblock of updating of position indications
- Substitution of position indications
- Overriding of interlocking functions
- Overriding of synchronism check
- Operation counter
- Suppression of Mid position

The apparatus control function is realized by means of a number of function blocks designated:

- Switch controller SCSWI
- Circuit breaker SXCBR
- Circuit switch SXSWI
- Position evaluation POS_EVAL
- Select release SELGGIO

- Bay control QCBAY
- Local remote LOCREM
- Local remote control LOCREMCTRL

SCSWI, SXCBR, QCBAY and SXSWI are logical nodes according to IEC 61850. The signal flow between these function blocks appears in figure 108. The function Logical node Interlocking (SCILO) in the figure 108 is the logical node for interlocking.

Control operation can be performed from the local IED HMI. If the administrator has defined users with the UMT tool, then the local/remote switch is under authority control. If not, the default (factory) user is the SuperUser that can perform control operations from the local IED HMI without LogOn. The default position of the local/remote switch is on remote.

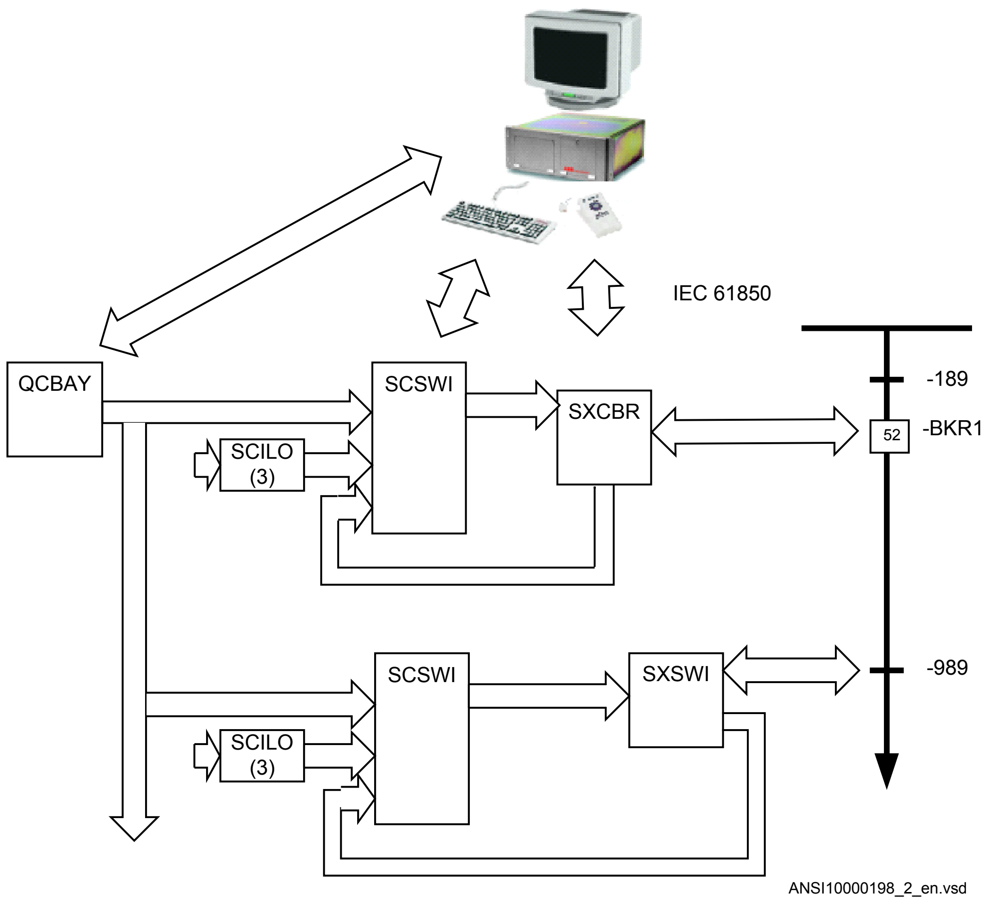


Figure 108: Signal flow between apparatus control function blocks

The IEC 61850 communication has always priority over binary inputs, e.g. a block command on binary inputs will not prevent commands over IEC 61850.

Bay control (QCBAY)

The Bay control (QCBAY) is used to handle the selection of the operator place for the bay. The function gives permission to operate from two types of locations either from Remote (for example, control centre or station HMI) or from Local (local HMI on the IED) or from all (Local and Remote). The Local/Remote switch position can also be set to Off, which means no operator place selected that is, operation is not possible neither from local nor from remote.

QCBAY also provides blocking functions that can be distributed to different apparatuses within the bay. There are two different blocking alternatives:

- Blocking of update of positions
- Blocking of commands

The function does not have a corresponding functionality defined in the IEC 61850 standard, which means that this function is included as a vendor specific logical node.

12.2.3 Interaction between modules

A typical bay with apparatus control function consists of a combination of logical nodes or functions that are described here:

- The Switch controller (SCSWI) initializes all operations for one apparatus and performs the actual switching and is more or less the interface to the drive of one apparatus. It includes the position handling as well as the control of the position.
- The Circuit breaker (SXCBR) is the process interface to the circuit breaker for the apparatus control function.
- The Circuit switch (SXSWI) is the process interface to the disconnector or the grounding switch for the apparatus control function.
- The Bay control (QCBAY) fulfils the bay-level functions for the apparatuses, such as operator place selection and blockings for the complete bay.
- The function (SELGGIO), deals with reservation of the bay.
- The Four step overcurrent protection (OC4PTOC, 51/67) trips the breaker.
- The Protection trip logic (SMPPTRC, 94) connects the "trip" outputs of one or more protection functions to a common "trip" to be transmitted to SXCBR.
- The Autorecloser (SMBRREC, 79) consists of the facilities to automatically close a tripped breaker with respect to a number of configurable conditions.

- The logical node Interlocking (SCILO, 3) provides the information to SCSWI whether it is permitted to operate due to the switchyard topology. The interlocking conditions are evaluated with separate logic and connected to SCILO (3).
- The Synchronism, energizing check, and synchronizing (SESRSYN, 25) calculates and compares the voltage phasor difference from both sides of an open breaker with predefined switching conditions (synchronism check). Also the case that one side is dead (energizing-check) is included.
- The logical node Generic Automatic Process Control, GAPC, is an automatic function that reduces the interaction between the operator and the system. With one command, the operator can start a sequence that will end with a connection of a process object (for example a line) to one of the possible busbars.

The overview of the interaction between these functions is shown in figure 109 below.

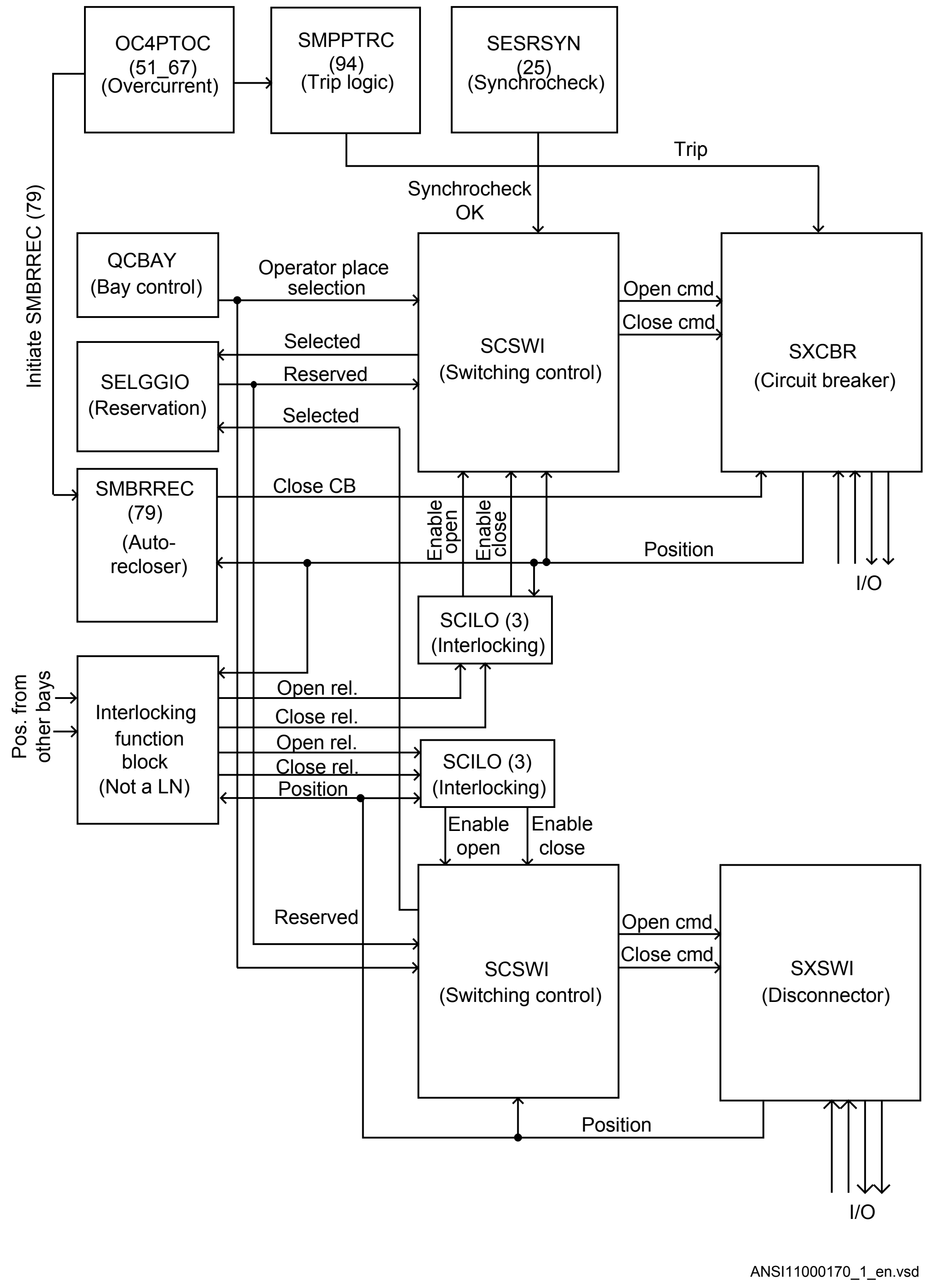


Figure 109: Example overview of the interactions between functions in a typical bay

12.2.4 Setting guidelines

The setting parameters for the apparatus control function are set via the local HMI or PCM600.

12.2.4.1 Bay control (QCBAY)

If the parameter *AllPSTOValid* is set to *No priority*, all originators from local and remote are accepted without any priority.

12.3 Logic rotating switch for function selection and LHMI presentation SLGGIO

12.3.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Logic rotating switch for function selection and LHMI presentation	SLGGIO	-	-

12.3.2 Application

The logic rotating switch for function selection and LHMI presentation function (SLGGIO) (or the selector switch function block, as it is also known) is used to get a selector switch functionality similar with the one provided by a hardware multi-position selector switch. Hardware selector switches are used extensively by utilities, in order to have different functions operating on pre-set values. Hardware switches are however sources for maintenance issues, lower system reliability and extended purchase portfolio. The virtual selector switches eliminate all these problems.

SLGGIO function block has two operating inputs (UP and DOWN), one blocking input (BLOCK) and one operator position input (PSTO).

SLGGIO can be activated both from the local HMI and from external sources (switches), via the IED binary inputs. It also allows the operation from remote (like the station computer). SWPOSN is an integer value output, giving the actual output number. Since the number of positions of the switch can be established by settings (see below), one must be careful in coordinating the settings with the configuration (if one sets the number of positions to x in settings – for example, there will be only the first x outputs available from the block in the configuration). Also the frequency of the (UP or DOWN) pulses should be lower than the setting *tPulse*.

The operation from local HMI is from select or indication buttons (32 positions). Typical applications are: Select operating modes for e.g. Auto reclose, Energizing check, Ground fault protection (IN,UN). The output integer can be connected to an Integer to Binary function block to give the position as a boolean for use in the configuration.

12.3.3 Setting guidelines

The following settings are available for the Logic rotating switch for function selection and LHMI presentation (SLGGIO) function:

Operation: Sets the operation of the function *Enabled* or *Disabled*.

NrPos: Sets the number of positions in the switch (max. 32). This setting influence the behavior of the switch when changes from the last to the first position.

OutType: *Steady* or *Pulsed*.

tPulse: In case of a pulsed output, it gives the length of the pulse (in seconds).

tDelay: The delay between the UP or DOWN activation signal positive front and the output activation.

StopAtExtremes: Sets the behavior of the switch at the end positions – if set to *Disabled*, when pressing UP while on first position, the switch will jump to the last position; when pressing DOWN at the last position, the switch will jump to the first position; when set to *Enabled*, no jump will be allowed.

12.4 Selector mini switch VSGGIO

12.4.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Selector mini switch	VSGGIO	-	-

12.4.2 Application

Selector mini switch (VSGGIO) function is a multipurpose function used in the configuration tool in PCM600 for a variety of applications, as a general purpose switch. VSGGIO can be used for both acquiring an external switch position (through the IPOS1 and the IPOS2 inputs) and represent it through the single line diagram symbols (or use it in the configuration through the outputs POS1 and POS2) as well as,

a command function (controlled by the PSTO input), giving switching commands through the CMDPOS12 and CMDPOS21 outputs.

The output POSITION is an integer output, showing the actual position as an integer number 0 – 3.

An example where VSGGIO is configured to switch Autorecloser enabled–disabled from a button symbol on the local HMI is shown in Figure 12. The Close and Open buttons on the local HMI are normally used for enable–disable operations of the circuit breaker.

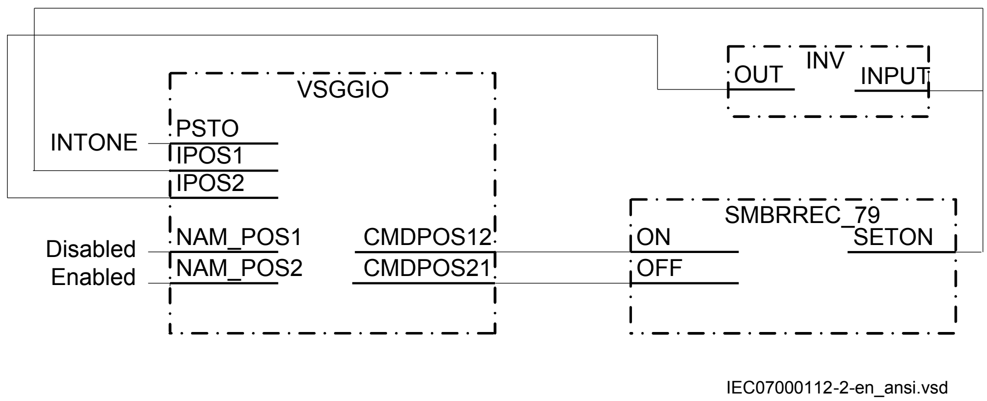


Figure 110: Control of Autorecloser from local HMI through Selector mini switch

12.4.3 Setting guidelines

Selector mini switch (VSGGIO) function can generate pulsed or steady commands (by setting the *Mode* parameter). When pulsed commands are generated, the length of the pulse can be set using the *tPulse* parameter. Also, being accessible on the single line diagram (SLD), this function block has two control modes (settable through *CtlModel*): *Dir Norm* and *SBO Enh*.

12.5 IEC61850 generic communication I/O functions DPGGIO

12.5.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
IEC 61850 generic communication I/O functions	DPGGIO	-	-

12.5.2 Application

The IEC61850 generic communication I/O functions (DPGGIO) function block is used to send three logical outputs to other systems or equipment in the substation. The three inputs are named OPEN, CLOSE and VALID, since this function block is intended to be used as a position indicator block in interlocking and reservation station-wide logics.

12.5.3 Setting guidelines

The function does not have any parameters available in the local HMI or PCM600.

12.6 Single point generic control 8 signals SPC8GGIO

12.6.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Single point generic control 8 signals	SPC8GGIO	-	-

12.6.2 Application

The Single point generic control 8 signals (SPC8GGIO) function block is a collection of 8 single point commands, designed to bring in commands from REMOTE (SCADA) to those parts of the logic configuration that do not need complicated function blocks that have the capability to receive commands (for example SCSWI). In this way, simple commands can be sent directly to the IED outputs, without confirmation. Confirmation (status) of the result of the commands is supposed to be achieved by other means, such as binary inputs and SPGGIO function blocks.

PSTO is the universal operator place selector for all control functions. Even if PSTO can be configured to allow LOCAL or ALL operator positions, the only functional position usable with the SPC8GGIO function block is REMOTE.

12.6.3 Setting guidelines

The parameters for the single point generic control 8 signals (SPC8GGIO) function are set via the local HMI or PCM600.

Operation: turning the function operation *Enabled*/*Disabled*.

There are two settings for every command output (totally 8):

Latchedx: decides if the command signal for output *x* is *Latched* (steady) or *Pulsed*.

tPulsex: if *Latchedx* is set to *Pulsed*, then *tPulsex* will set the length of the pulse (in seconds).

12.7 Automation bits AUTOBITS

12.7.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
AutomationBits, command function for DNP3	AUTOBITS	-	-

12.7.2 Application

The AUTOBITS function block (or the automation bits function block) is used within PCM600 in order to get into the configuration the commands coming through the DNP3 protocol.AUTOBITS function block have 32 individual outputs which each can be mapped as a Binary Output point in DNP3. The output is operated by a "Object 12" in DNP3. This object contains parameters for control-code, count, on-time and off-time. To operate an AUTOBITS output point, send a control-code of latch-On, latch-Off, pulse-On, pulse-Off, Trip or Close. The remaining parameters are regarded as appropriate. For example, pulse-On, on-time=100, off-time=300, count=5 would give 5 positive 100 ms pulses, 300 ms apart.

See the communication protocol manual for a detailed description of the DNP3 protocol

12.7.3 Setting guidelines

AUTOBITS function block has one setting, (*Operation*: *Enabled*/*Disabled*) enabling or disabling the function. These names will be seen in the DNP communication configuration tool in PCM600.

Section 13 Logic

13.1 Tripping logic common 3-phase output SMPPTRC (94)

13.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Tripping logic common 3-phase output	SMPPTRC	I->O	94

13.1.2 Application

All trip signals from the different protection functions shall be routed through the trip logic. In its simplest alternative the logic will only link the internal TRIP signals to a binary output and make sure that the pulse length is long enough.

The tripping logic common 3-phase output (SMPPTRC ,94) offers only three-pole tripping. A three-pole trip for all faults offers a simple solution and is often sufficient in well meshed transmission systems and in High Voltage (HV) systems.

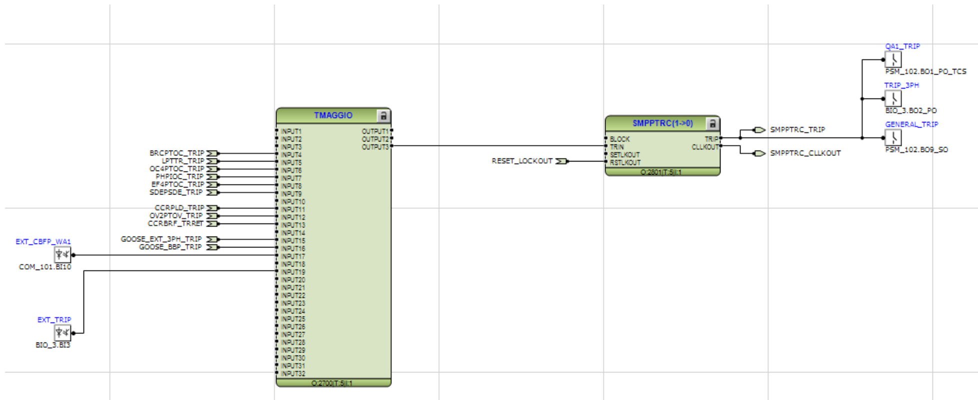
One SMPPTRC (94) function block should be used for each breaker, if the object is connected to the system via more than one breaker.

To prevent closing of a circuit breaker after a trip the function can block the closing of the circuit breaker (trip lock-out).

13.1.2.1 Three-pole tripping

A simple application with three-pole tripping from the tripping logic common 3-phase output SMPPTRC utilizes part of the function block. Connect the inputs from the protection function blocks to the input TRINP_3P. If necessary (normally the case) use the trip matrix logic TMAGGIO to combine the different function outputs to this input. Connect the output TRIP to the required binary outputs.

A typical connection is shown below in figure 111.



IEC11000054-1-en.vsd

Figure 111: Tripping logic common 3-phase output SMPPTRC (94) is used for a simple three-pole tripping application

13.1.2.2 Lock-out

This function block is provided with possibilities to initiate lock-out. The lock-out can be set to only activate the block closing output CLLKOUT or initiate the block closing output and also maintain the trip signal (latched trip).

The lock-out can then be manually reset after checking the primary fault by activating the input reset Lock-Out RSTLKOUT or via the HMI.

If external conditions are required to initiate Lock-out but not initiate trip this can be achieved by activating input SETLKOUT. The setting *AutoLock* = *Disabled* means that the internal trip will not activate lock-out so only initiation of the input SETLKOUT will result in lock-out. This is normally the case for overhead line protection where most faults are transient. Unsuccessful autoreclose and back-up zone tripping can in such cases be connected to initiate Lock-out by activating the input SETLKOUT.

13.1.2.3 Blocking of the function block

Blocking can be initiated internally by logic, or by the operator using a communication channel. Total blockage of Tripping logic (SMPPTRC ,94) function is done by activating the input BLOCK and can be used to block the output of SMPPTRC (94) in the event of internal failures.

13.1.3 Setting guidelines

The parameters for Tripping logic common 3-phase output SMPPTRC (94) are set via the local HMI or through the Protection and Control Manager (PCM600).

The following trip parameters can be set to regulate tripping.

Operation: Sets the mode of operation. *Disabled* switches the function off. The normal selection is *Enabled*.

TripLockout: Sets the scheme for lock-out. *Disabled* only activates the lock-out output. *Enabled* activates the lock-out output and latches the output `TRIP`. The normal selection is *Disabled*.

AutoLock: Sets the scheme for lock-out. *Disabled* only activates lock-out through the input SETLKOUT. *Enabled* additonally allows activation through the trip function itself. The normal selection is *Disabled*.

tTripMin: Sets the required minimum duration of the trip pulse. It should be set to ensure that the breaker is tripped correctly. Normal setting is *0.150s*.

13.2 Trip matrix logic TMAGGIO

13.2.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Trip matrix logic	TMAGGIO	-	-

13.2.2 Application

The Trip matrix logic TMAGGIO function is used to route trip signals and other logical output signals to the tripping logics SMPPTRC and SPTPTRC or to different output contacts on the IED.

TMAGGIO output signals and the physical outputs allows the user to adapt the signals to the physical tripping outputs according to the specific application needs.

13.2.3 Setting guidelines

Operation: Turns the operation of the function *Enabled*/*Disabled*.

PulseTime: Defines the pulse time duration. When used for direct tripping of circuit breaker(s) the pulse time duration shall be set to approximately 0.150 seconds in order to obtain satisfactory minimum duration of the trip pulse to the circuit breaker trip coils. Used only for *ModeOutputx*: *Pulsed*.

OnDelay: Used to prevent output signals to be given for spurious inputs. Normally set to 0 or a low value. Used only for *ModeOutputx*: *Steady*.

OffDelay: Defines a minimum on time for the outputs. When used for direct tripping of circuit breaker(s) the off delay time shall be set to approximately 0.150 seconds in order to obtain a satisfactory minimum duration of the trip pulse to the circuit breaker trip coils. Used only for *ModeOutputx*: *Steady*.

ModeOutputx: Defines if output signal `OUTPUTx` (where x=1-3) is *Steady* or *Pulsed*. A steady signal follows the status of the input signals, with respect to *OnDelay* and *OffDelay*. A pulsed signal will give a pulse once, when the `Outputx` rises from 0 to 1.

13.3 Configurable logic blocks

13.3.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
OR Function block	OR	-	-

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Inverter function block	INVERTER	-	-

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
PULSETIMER function block	PULSETIMER	-	-

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Controllable gate function block	GATE	-	-

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Exclusive OR function block	XOR	-	-

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Logic loop delay function block	LOOPDELAY	-	-

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Timer function block	TIMERSET	-	-

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
AND function block	AND	-	-

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Set-reset memory function block	SRMEMORY	-	-

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Reset-set with memory function block	RSMEMORY	-	-

13.3.2 Application

A set of standard logic blocks, like AND, OR etc, and timers are available for adapting the IED configuration to the specific application needs.

There are no settings for AND gates, OR gates, inverters or XOR gates.

For normal On/Off delay and pulse timers the time delays and pulse lengths are set from the local HMI or via the PST tool.

Both timers in the same logic block (the one delayed on pick-up and the one delayed on drop-out) always have a common setting value.

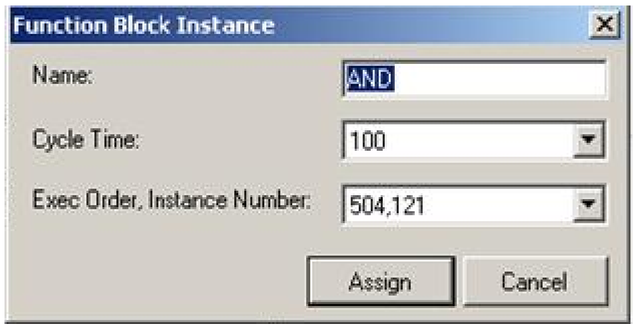
For controllable gates, settable timers and SR flip-flops with memory, the setting parameters are accessible via the local HMI or via the PST tool.

13.3.3.1 Configuration

Logic is configured using the ACT configuration tool in PCM600.

Execution of functions as defined by the configurable logic blocks runs according to a fixed sequence with different cycle times.

For each cycle time, the function block is given an serial execution number. This is shown when using the ACT configuration tool with the designation of the function block and the cycle time, see example below.



IEC09000695_2_en.vsd

Figure 112: Example designation, serial execution number and cycle time for logic function

The execution of different function blocks within the same cycle is determined by the order of their serial execution numbers. Always remember this when connecting two or more logical function blocks in series.

Always be careful when connecting function blocks with a fast cycle time to function blocks with a slow cycle time.
Remember to design the logic circuits carefully and always check the execution sequence for different functions. In other cases, additional time delays must be introduced into the logic schemes to prevent errors, for example, race between functions.
Default value on all four inputs of the AND gate are logical 1 which makes it possible for the user to just use the required number of inputs and leave the rest un-connected. The output OUT has a default value 0 initially, which will suppress one cycle pulse if the function has been put in the wrong execution order.

13.4 Fixed signals FXDSIGN

13.4.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Fixed signals	FXDSIGN	-	-

13.4.2 Application

The Fixed signals function (FXDSIGN) generates a number of pre-set (fixed) signals that can be used in the configuration of an IED, either for forcing the unused inputs in other function blocks to a certain level/value, or for creating certain logic.

Example for use of GRP_OFF signal in FXDSIGN

The Restricted earth fault function REFPDIF (87N) can be used both for auto-transformers and normal transformers.

When used for auto-transformers, information from both windings parts, together with the neutral point current, needs to be available to the function. This means that three inputs are needed.

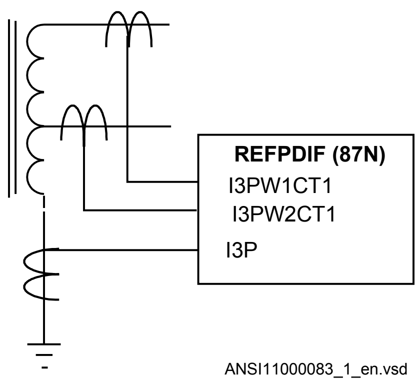


Figure 113: REFPDIF (87N) function inputs for autotransformer application

For normal transformers only one winding and the neutral point is available. This means that only two inputs are used. Since all group connections are mandatory to be connected, the third input needs to be connected to something, which is the GRP_OFF signal in FXDSIGN function block.

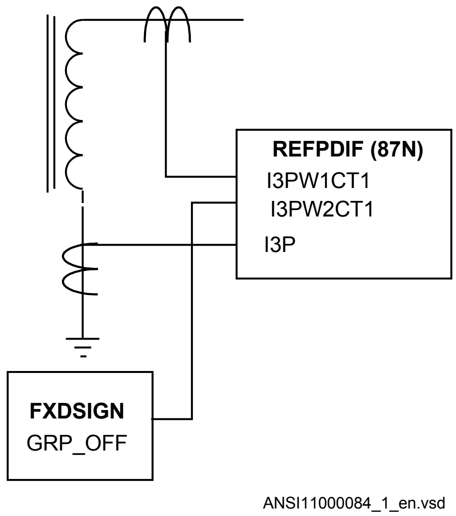


Figure 114: REFPDIF (87N) function inputs for normal transformer application

13.5 Boolean 16 to integer conversion B16I

13.5.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Boolean 16 to integer conversion	B16I	-	-

13.5.2 Application

Boolean 16 to integer conversion function B16I is used to transform a set of 16 binary (logical) signals into an integer. It can be used – for example, to connect logical output signals from a function (like distance protection) to integer inputs from another function (like line differential protection). B16I does not have a logical node mapping.

13.5.3 Setting guidelines

The function does not have any parameters available in Local HMI or Protection and Control IED Manager (PCM600).

13.6 Boolean 16 to integer conversion with logic node representation B16IFCVI

13.6.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Boolean 16 to integer conversion with logic node representation	B16IFCVI	-	-

13.6.2 Application

Boolean 16 to integer conversion with logic node representation function B16IFCVI is used to transform a set of 16 binary (logical) signals into an integer. B16IFCVI can receive an integer from a station computer – for example, over IEC 61850–8–1. These functions are very useful when you want to generate logical commands (for selector switches or voltage controllers) by inputting an integer number. B16IFCVI has a logical node mapping in IEC 61850.

13.6.3 Setting guidelines

The function does not have any parameters available in the local HMI or Protection and Control IED Manager (PCM600).

13.7 Integer to boolean 16 conversion IB16A

13.7.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Integer to boolean 16 conversion	IB16A	-	-

13.7.2 Application

Integer to boolean 16 conversion function (IB16A) is used to transform an integer into a set of 16 binary (logical) signals. It can be used – for example, to connect integer output signals from one function to binary (logical) inputs to another function. IB16A function does not have a logical node mapping.

13.7.3 Setting guidelines

The function does not have any parameters available in the local HMI or Protection and Control IED Manager (PCM600).

13.8 Integer to boolean 16 conversion with logic node representation IB16FCVB

13.8.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Integer to boolean 16 conversion with logic node representation	IB16FCVB	-	-

13.8.2 Application

Integer to boolean 16 conversion with logic node representation function (IB16FCVB) is used to transform an integer into a set of 16 binary (logical) signals. IB16FCVB function can receive an integer from a station computer – for example, over IEC 61850–8–1. These functions are very useful when the user wants to generate logical commands (for selector switches or voltage controllers) by inputting an integer number. IB16FCVB function has a logical node mapping in IEC 61850.

13.8.3 Settings

The function does not have any parameters available in the local HMI or Protection and Control IED Manager (PCM600)

Section 14 Monitoring

14.1 IEC61850 generic communication I/O functions SPGGIO

14.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
IEC 61850 generic communication I/O functions	SPGGIO	-	-

14.1.2 Application

IEC 61850–8–1 generic communication I/O functions (SPGGIO) function is used to send one single logical output to other systems or equipment in the substation. It has one visible input, that should be connected in ACT tool.

14.1.3 Setting guidelines

The function does not have any parameters available in Local HMI or Protection and Control IED Manager (PCM600).

14.2 IEC61850 generic communication I/O functions 16 inputs SP16GGIO

14.2.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
IEC 61850 generic communication I/O functions 16 inputs	SP16GGIO	-	-

14.2.2 Application

SP16GGIO function block is used to send up to 16 logical signals to other systems or equipment in the substation. Inputs should be connected in ACT tool.

14.2.3 Setting guidelines

The function does not have any parameters available in Local HMI or Protection and Control IED Manager (PCM600).

14.3 IEC61850 generic communication I/O functions MVGGIO

14.3.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
IEC61850 generic communication I/O functions	MVGGIO	-	-

14.3.2 Application

IEC61850 generic communication I/O functions (MVGGIO) function is used to send the instantaneous value of an analog signal to other systems or equipment in the substation. It can also be used inside the same IED, to attach a RANGE aspect to an analog value and to permit measurement supervision on that value.

14.3.3 Setting guidelines

The settings available for IEC61850 generic communication I/O functions (MVGGIO) function allows the user to choose a deadband and a zero deadband for the monitored signal. Values within the zero deadband are considered as zero.

The high and low limit settings provides limits for the high-high-, high, normal, low and low-low ranges of the measured value. The actual range of the measured value is shown on the range output of MVGGIO function block. When a Measured value expander block (MVEXP) is connected to the range output, the logical outputs of the MVEXP are changed accordingly.

14.4 Measurements

14.4.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Measurements	CVMMXN	P, Q, S, I, U, f	-
Phase current measurement	CMMXU	I	-
Phase-phase voltage measurement	VMMXU	U	-
Current sequence component measurement	CMSQI	I1, I2, I0	-
Voltage sequence measurement	VMSQI	U1, U2, U0	-
Phase-neutral voltage measurement	VNMMXU	U	-

14.4.2 Application

Measurement functions is used for power system measurement, supervision and reporting to the local HMI, monitoring tool within PCM600 or to station level for example, via IEC 61850. The possibility to continuously monitor measured values of active power, reactive power, currents, voltages, frequency, power factor etc. is vital for efficient production, transmission and distribution of electrical energy. It provides to the system operator fast and easy overview of the present status of the power system. Additionally, it can be used during testing and commissioning of protection and control IEDs in order to verify proper operation and connection of instrument transformers

(CTs and VTs). During normal service by periodic comparison of the measured value from the IED with other independent meters the proper operation of the IED analog measurement chain can be verified. Finally, it can be used to verify proper direction orientation for distance or directional overcurrent protection function.

The available measured values of an IED are depending on the actual hardware (TRM) and the logic configuration made in PCM600.

All measured values can be supervised with four settable limits that is, low-low limit, low limit, high limit and high-high limit. A zero clamping reduction is also supported, that is, the measured value below a settable limit is forced to zero which reduces the impact of noise in the inputs. There are no interconnections regarding any settings or parameters, neither between functions nor between signals within each function.

Zero clampings are handled by *ZeroDb* for each signal separately for each of the functions. For example, the zero clamping of U12 is handled by *VLZeroDB* in VMMXU, zero clamping of I1 is handled by *ILZeroDb* in CMMXU.

Dead-band supervision can be used to report measured signal value to station level when change in measured value is above set threshold limit or time integral of all changes since the last time value updating exceeds the threshold limit. Measure value can also be based on periodic reporting.

The measurement function, CVMMXN, provides the following power system quantities:

- P, Q and S: three phase active, reactive and apparent power
- PF: power factor
- V: phase-to-phase voltage magnitude
- I: phase current magnitude
- F: power system frequency

The output values are displayed in the local HMI under **Main menu/Tests/Function status/Monitoring/CVMMXN/Outputs**

The measuring functions CMMXU, VNMMXU and VMMXU provide physical quantities:

- I: phase currents (magnitude and angle) (CMMXU)
- V: voltages (phase-to-ground and phase-to-phase voltage, magnitude and angle) (VMMXU, VNMMXU)

It is possible to calibrate the measuring function above to get better then class 0.5 presentation. This is accomplished by angle and magnitude compensation at 5, 30 and 100% of rated current and at 100% of rated voltage.

The power system quantities provided, depends on the actual hardware, (TRM) and the logic configuration made in PCM600.

The measuring functions CMSQI and VMSQI provide sequence component quantities:

- I: sequence currents (positive, zero, negative sequence, magnitude and angle)
- V: sequence voltages (positive, zero and negative sequence, magnitude and angle).

The CVMMXN function calculates three-phase power quantities by using fundamental frequency phasors (DFT values) of the measured current respectively voltage signals. The measured power quantities are available either, as instantaneously calculated quantities or, averaged values over a period of time (low pass filtered) depending on the selected settings.

14.4.3 Setting guidelines

The available setting parameters of the measurement function CVMMXN, CMMXU, VMMXU, CMSQI, VMSQI, VNMMXU are depending on the actual hardware (TRM) and the logic configuration made in PCM600.

The parameters for the Measurement functions CVMMXN, CMMXU, VMMXU, CMSQI, VMSQI, VNMMXU are set via the local HMI or PCM600.

GlobalBaseSel: Selects the global base value group used by the function to define (*IBase*), (*VBase*) and (*SBase*).

Operation: *Disabled*/*Enabled*. Every function instance (CVMMXN, CMMXU, VMMXU, CMSQI, VMSQI, VNMMXU) can be taken in operation (*Enabled*) or out of operation (*Disabled*).

The following general settings can be set for the **Measurement function** (CVMMXN).

PowMagFact: Magnitude factor to scale power calculations.

PowAngComp: Angle compensation for phase shift between measured I & V.

Mode: Selection of measured current and voltage. There are 9 different ways of calculating monitored three-phase values depending on the available VT inputs connected to the IED. See parameter group setting table.

k: Low pass filter coefficient for power measurement, V and I.

VMagCompY: Magnitude compensation to calibrate voltage measurements at Y% of Vn, where Y is equal to 5, 30 or 100.

IMagCompY: Magnitude compensation to calibrate current measurements at Y% of In, where Y is equal to 5, 30 or 100.

IAngCompY: Angle compensation to calibrate angle measurements at Y% of In, where Y is equal to 5, 30 or 100.

The following general settings can be set for the **Phase-phase current measurement** (CMMXU).

IMagCompY: Magnitude compensation to calibrate current measurements at Y% of In, where Y is equal to 5, 30 or 100.

IAngCompY: Angle compensation to calibrate angle measurements at Y% of In, where Y is equal to 5, 30 or 100.

The following general settings can be set for the **Phase-phase voltage measurement** (VMMXU).

VMagCompY: Amplitude compensation to calibrate voltage measurements at Y% of Vn, where Y is equal to 5, 30 or 100.

VAngCompY: Angle compensation to calibrate angle measurements at Y% of Vn, where Y is equal to 5, 30 or 100.

The following general settings can be set for **all monitored quantities** included in the functions (CVMMXN, CMMXU, VMMXU, CMSQI, VMSQI, VNMMXU) X in setting names below equals S, P, Q, PF, V, I, F, IA,IB,IC, VA, VB, VCVAB, VBC, VCA, I1, I2, 3I0, V1, V2 or 3V0.

Xmin: Minimum value for analog signal X.

Xmax: Maximum value for analog signal X.

Xmin and *Xmax* values are directly set in applicable measuring unit, V, A, and so on, for all measurement functions, except CVMMXN where *Xmin* and *Xmax* values are set in % of *SBase*.

XZeroDb: Zero point clamping. A signal value less than *XZeroDb* is forced to zero.

XRepTyp: Reporting type. Cyclic (*Cyclic*), magnitude deadband (*Dead band*) or integral deadband (*Int deadband*). The reporting interval is controlled by the parameter *XDbRepInt*.

XDbRepInt: Reporting deadband setting. Cyclic reporting is the setting value and is reporting interval in seconds. Magnitude deadband is the setting value in % of measuring range. Integral deadband setting is the integral area, that is, measured value in % of measuring range multiplied by the time between two measured values.

Limits are directly set in applicable measuring unit, V, A , and so on, for all measureing functions, except CVMMXN where limits are set in % of *SBase*.

XHiHiLim: High-high limit.

XHiLim: High limit.

XLowLim: Low limit.

XLowLowLim: Low-low limit.

XLimHyst: Hysteresis value in % of range and is common for all limits.

All phase angles are presented in relation to defined reference channel. The parameter *PhaseAngleRef* defines the reference.

Calibration curves

It is possible to calibrate the functions (CVMMXN, CMMXU, VNMMXU and VMMXU) to get class 0.5 presentations of currents, voltages and powers. This is accomplished by magnitude and angle compensation at 5, 30 and 100% of rated current and voltage. The compensation curve will have the characteristic for magnitude and angle compensation of currents as shown in figure 115 (example). The first phase will be used as reference channel and compared with the curve for calculation of factors. The factors will then be used for all related channels.

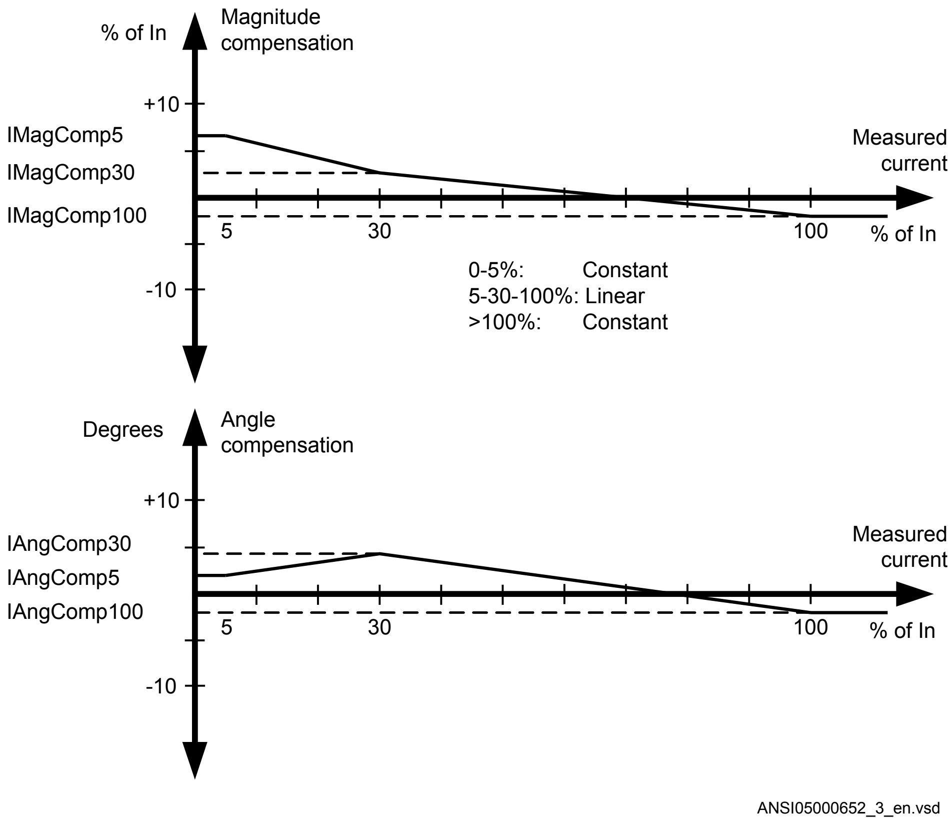


Figure 115: Calibration curves

14.4.4 Setting examples

Three setting examples, in connection to Measurement function (CVMMXN), are provided:

- Measurement function (CVMMXN) application for a 400 kV OHL
- Measurement function (CVMMXN) application on the secondary side of a transformer
- Measurement function (CVMMXN) application for a generator

For each of them detail explanation and final list of selected setting parameters values will be provided.

The available measured values of an IED are depending on the actual hardware (TRM) and the logic configuration made in PCM600.

14.4.4.1 Measurement function application for a 380 kV OHL

Single line diagram for this application is given in figure 116:

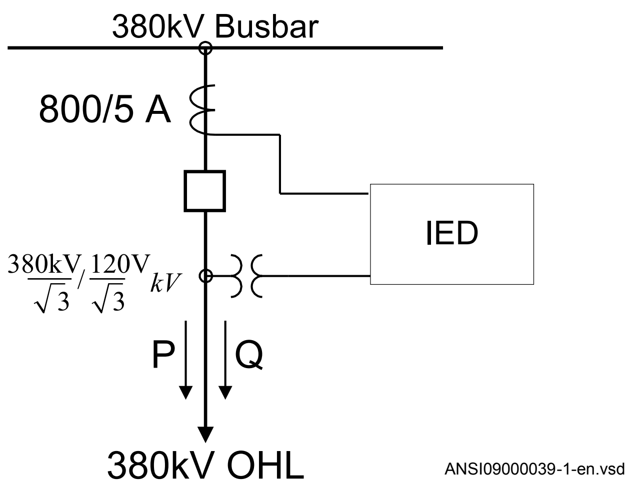


Figure 116: Single line diagram for 380 kV OHL application

In order to monitor, supervise and calibrate the active and reactive power as indicated in figure 116 it is necessary to do the following:

1. Set correctly CT and VT data and phase angle reference channel *PhaseAngleRef* using PCM600 for analog input channels
2. Connect, in PCM600, measurement function to three-phase CT and VT inputs
3. Set under General settings parameters for the Measurement function:
    - general settings as shown in table 30.
    - level supervision of active power as shown in table 31.
    - calibration parameters as shown in table 32.

Table 30: *General settings parameters for the Measurement function*

Setting	Short Description	Selected value	Comments
Operation	Operation *Disabled*/*Enabled*	*Enabled*	Function must be *Enabled*
PowMagFact	Magnitude factor to scale power calculations	1.000	It can be used during commissioning to achieve higher measurement accuracy. Typically no scaling is required
PowAngComp	Angle compensation for phase shift between measured I & V	0.0	It can be used during commissioning to achieve higher measurement accuracy. Typically no angle compensation is required. As well here required direction of P & Q measurement is towards protected object (as per IED internal default direction)
Mode	Selection of measured current and voltage	*A, B, C*	All three phase-to-ground VT inputs are available
k	Low pass filter coefficient for power measurement, V and I	0.00	Typically no additional filtering is required

Table 31: *Settings parameters for level supervision*

Setting	Short Description	Selected value	Comments
PMin	Minimum value	-750	Minimum expected load
PMax	Minimum value	750	Maximum expected load
PZeroDb	Zero point clamping in 0.001% of range	3000	Set zero point clamping to 45 MW that is, 3% of 1500 MW
PRepTyp	Reporting type	db	Select magnitude deadband supervision
PDbRepInt	Cycl: Report interval (s), Db: In % of range, Int Db: In %s	2	Set ±Δdb=30 MW that is, 2% (larger changes than 30 MW will be reported)
PHiHiLim	High High limit (physical value)	600	High alarm limit that is, extreme overload alarm
PHiLim	High limit (physical value)	500	High warning limit that is, overload warning
PLowLim	Low limit (physical value)	-800	Low warning limit. Not active
PLowLowlLim	Low Low limit (physical value)	-800	Low alarm limit. Not active
PLimHyst	Hysteresis value in % of range (common for all limits)	2	Set ±Δ Hysteresis MW that is, 2%

Table 32: Settings for calibration parameters

Setting	Short Description	Selected value	Comments
IMagComp5	Magnitude factor to calibrate current at 5% of In	0.00	
IMagComp30	Magnitude factor to calibrate current at 30% of In	0.00	
IMagComp100	Magnitude factor to calibrate current at 100% of In	0.00	
VAmpComp5	Magnitude factor to calibrate voltage at 5% of Vn	0.00	
VMagComp30	Magnitude factor to calibrate voltage at 30% of Vn	0.00	
VMagComp100	Magnitude factor to calibrate voltage at 100% of Vn	0.00	
IAngComp5	Angle calibration for current at 5% of In	0.00	
IAngComp30	Angle pre-calibration for current at 30% of In	0.00	
IAngComp100	Angle pre-calibration for current at 100% of In	0.00	

14.4.4.2 Measurement function application for a generator

Single line diagram for this application is given in figure 117.

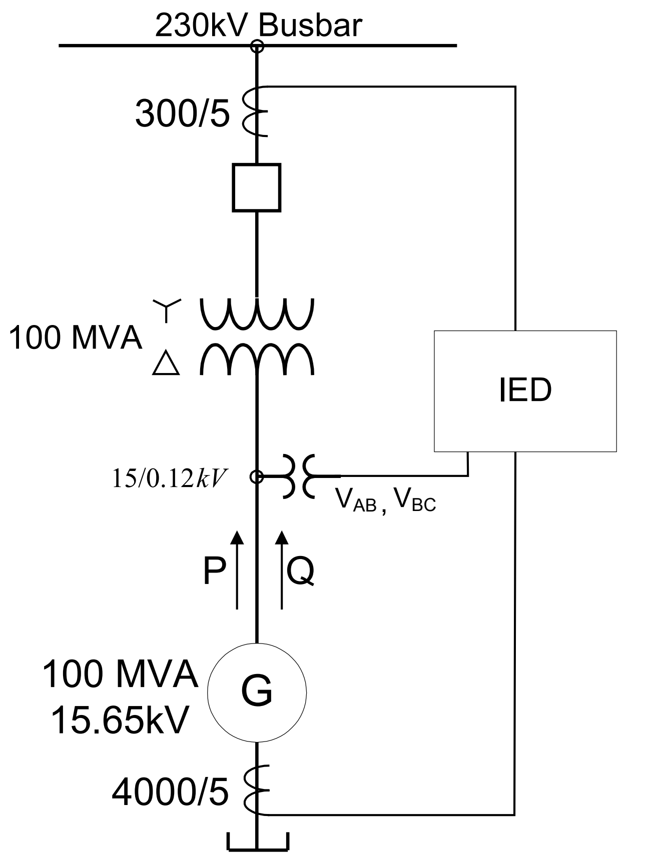


Figure 117: Single line diagram for generator application

In order to measure the active and reactive power as indicated in figure 117, it is necessary to do the following:

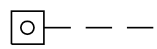
1. Set correctly all CT and VT data and phase angle reference channel *PhaseAngleRef* using PCM600 for analog input channels
2. Connect, in PCM600, measurement function to the generator CT & VT inputs
3. Set the setting parameters for relevant Measurement function as shown in the following table:

Table 33: General settings parameters for Measurement function

Setting	Short description	Selected value	Comment
Operation	Operation *Disabled/Enabled*	*Enabled*	Function must be *Enabled*
PowMagFact	Magnitude factor to scale power calculations	1.000	Typically no scaling is required
PowAngComp	Angle compensation for phase shift between measured I & V	0.0	Typically no angle compensation is required. As well here required direction of P & Q measurement is towards protected object (as per IED internal default direction)
Mode	Selection of measured current and voltage	*Arone*	Generator VTs are connected between phases (V-connected)
k	Low pass filter coefficient for power measurement, V and I	0.00	Typically no additional filtering is required

14.5 Event counter CNTGGIO

14.5.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Event counter	CNTGGIO		-

14.5.2 Application

Event counter (CNTGGIO) has six counters which are used for storing the number of times each counter has been activated. CNTGGIO can be used to count how many times a specific function, for example the tripping logic, has issued a trip signal. All six counters have a common blocking and resetting feature.

14.5.3 Setting guidelines

Operation: Sets the operation of Event counter (CNTGGIO) *Enabled* or *Disabled*.

14.6 Disturbance report

14.6.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Disturbance report	DRPRDRE	-	-
Analog input signals	A1RADR	-	-
Analog input signals	A2RADR	-	-
Analog input signals	A3RADR	-	-
Analog input signals	A4RADR	-	-
Binary input signals	B1RBDR	-	-
Binary input signals	B2RBDR	-	-
Binary input signals	B3RBDR	-	-
Binary input signals	B4RBDR	-	-
Binary input signals	B5RBDR	-	-
Binary input signals	B6RBDR	-	-

14.6.2 Application

To get fast, complete and reliable information about disturbances in the primary and/or in the secondary system it is very important to gather information on fault currents, voltages and events. It is also important having a continuous event-logging to be able to monitor in an overview perspective. These tasks are accomplished by the disturbance report function DRPRDRE and facilitate a better understanding of the power system behavior and related primary and secondary equipment during and after a disturbance. An analysis of the recorded data provides valuable information that can be used to explain a disturbance, basis for change of IED setting plan, improve existing equipment, and so on. This information can also be used in a longer perspective when planning for and designing new installations, that is, a disturbance recording could be a part of Functional Analysis (FA).

Disturbance report DRPRDRE, always included in the IED, acquires sampled data of all selected analog and binary signals connected to the function blocks that is,

- maximum 30 external analog signals,
- 10 internal derived analog signals, and
- 96 binary signals.

Disturbance report function is a common name for several functions that is, Indications, Event recorder, Sequential of events, Trip value recorder, Disturbance recorder.

Disturbance report function is characterized by great flexibility as far as configuration, starting conditions, recording times, and large storage capacity are concerned. Thus, disturbance report is not dependent on the operation of protective functions, and it can record disturbances that were not discovered by protective functions for one reason or another. Disturbance report can be used as an advanced stand-alone disturbance recorder.

Every disturbance report recording is saved in the IED. The same applies to all events, which are continuously saved in a ring-buffer. Local HMI can be used to get information about the recordings, and the disturbance report files may be uploaded in the PCM600 using the Disturbance handling tool, for report reading or further analysis (using WaveWin, that can be found on the PCM600 installation CD). The user can also upload disturbance report files using FTP or MMS (over 61850–8–1) clients.

If the IED is connected to a station bus (IEC 61850-8-1), the disturbance recorder (record made and fault number) and the fault locator information are available as GOOSE or Report Control data.

14.6.3 Setting guidelines

The setting parameters for the Disturbance report function DRPRDRE are set via the local HMI or PCM600.

It is possible to handle up to 40 analog and 96 binary signals, either internal signals or signals coming from external inputs. The binary signals are identical in all functions that is, Disturbance recorder, Event recorder, Indication, Trip value recorder and Sequential of events function.

User-defined names of binary and analog input signals is set using PCM600. The analog and binary signals appear with their user-defined names. The name is used in all related functions (Disturbance recorder, Event recorder, Indication, Trip value recorder and Sequential of events).

Figure 118 shows the relations between Disturbance report, included functions and function blocks. Sequential of events , Event recorder and Indication uses information from the binary input function blocks (BxRBDR). Trip value recorder uses analog information from the analog input function blocks (AxRADR),. Disturbance report function acquires information from both AxRADR and BxRBDR.

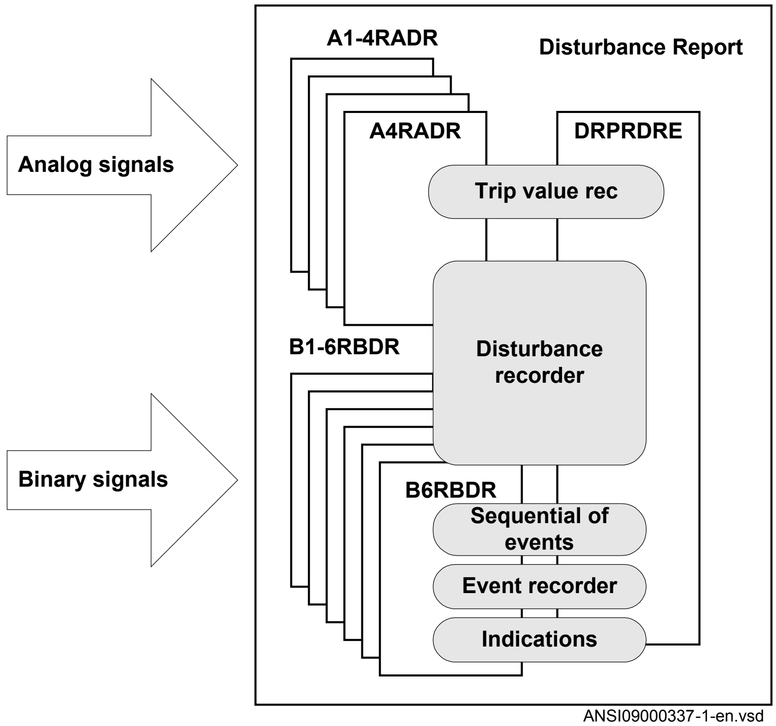


Figure 118: Disturbance report functions and related function blocks

For Disturbance report function there are a number of settings which also influences the sub-functions.

Three LED indications placed above the LCD screen makes it possible to get quick status information about the IED.

Green LED:	Steady light	In Service
	Flashing light	Internal failure
	Dark	No power supply
Yellow LED:	Function controlled by SetLEDn setting in Disturbance report function.	
Red LED:	Function controlled by SetLEDn setting in Disturbance report function.	

Operation

The operation of Disturbance report function DRPRDRE has to be set *Enabled* or *Disabled*. If *Disabled* is selected, note that no disturbance report is registered, and none sub-function will operate (the only general parameter that influences Sequential of events).

Operation = *Disabled*:

- Disturbance reports are not stored.
- LED information (yellow - pickup, red - trip) is not stored or changed.

Operation = *Enabled*:

- Disturbance reports are stored, disturbance data can be read from the local HMI and from a PC using PCM600.
- LED information (yellow - pickup, red - trip) is stored.

Every recording will get a number (0 to 999) which is used as identifier (local HMI, disturbance handling tool and IEC 61850). An alternative recording identification is date, time and sequence number. The sequence number is automatically increased by one for each new recording and is reset to zero at midnight. The maximum number of recordings stored in the IED is 100. The oldest recording will be overwritten when a new recording arrives (FIFO).

To be able to delete disturbance records, *Operation* parameter has to be *Enabled*.

The maximum number of recordings depend on each recordings total recording time. Long recording time will reduce the number of recordings to less than 100.

The IED flash disk should NOT be used to store any user files. This might cause disturbance recordings to be deleted due to lack of disk space.

Recording times

Prefault recording time (*PreFaultRecT*) is the recording time before the starting point of the disturbance. The setting should be at least *0.1* s to ensure enough samples for the estimation of pre-fault values in the Trip value recorder function.

Postfault recording time (*PostFaultRecT*) is the maximum recording time after the disappearance of the trig-signal (does not influence the Trip value recorder function).

Recording time limit (*TimeLimit*) is the maximum recording time after trig. The parameter limits the recording time if some trigging condition (fault-time) is very long or permanently set (does not influence the Trip value recorder function).

Post retrigger (*PostRetrig*) can be set to *Enabled* or *Disabled*. Makes it possible to choose performance of Disturbance report function if a new trig signal appears in the post-fault window.

PostRetrig = *Disabled*

The function is insensitive for new trig signals during post fault time.

PostRetrig = *Enabled*

The function completes current report and starts a new complete report that is, the latter will include:

- new pre-fault- and fault-time (which will overlap previous report)
- events and indications might be saved in the previous report too, due to overlap
- new trip value calculations if installed, in operation and started

Operation in test mode

If the IED is in test mode and *OpModeTest* = *Disabled*. Disturbance report function does not save any recordings and no LED information is displayed.

If the IED is in test mode and *OpModeTest* = *Enabled*. Disturbance report function works in normal mode and the status is indicated in the saved recording.

14.6.3.1 Binary input signals

Up to 96 binary signals can be selected among internal logical and binary input signals. The configuration tool is used to configure the signals.

For each of the 96 signals, it is also possible to select if the signal is to be used as a trigger for the start of the Disturbance report and if the trigger should be activated on positive (1) or negative (0) slope.

TrigDRN: Disturbance report may trig for binary input N (*Enabled*) or not (*Disabled*).

TrigLevelN: Trig on positive (*Trig on 1*) or negative (*Trig on 0*) slope for binary input N.

14.6.3.2 Analog input signals

Up to 40 analog signals can be selected among internal analog and analog input signals. PCM600 is used to configure the signals.

The analog trigger of Disturbance report is not affected if analog input M is to be included in the disturbance recording or not (*OperationM* = *Enabled*/*Disabled*).

If *OperationM* = *Disabled*, no waveform (samples) will be recorded and reported in graph. However, Trip value, pre-fault and fault value will be recorded and reported. The input channel can still be used to trig the disturbance recorder.

If *OperationM* = *Enabled*, waveform (samples) will also be recorded and reported in graph.

NomValueM: Nominal value for input M.

OverTrigOpM, *UnderTrigOpM*: Over or Under trig operation, Disturbance report may trig for high/low level of analog input M (*Enabled*) or not (*Disabled*).

OverTrigLeM, *UnderTrigLeM*: Over or under trig level, Trig high/low level relative nominal value for analog input M in percent of nominal value.

14.6.3.3 Sub-function parameters

All functions are in operation as long as Disturbance report is in operation.

Indications

IndicationMaN: Indication mask for binary input N. If set (*Show*), a status change of that particular input, will be fetched and shown in the disturbance summary on local HMI. If not set (*Hide*), status change will not be indicated.

SetLEDN: Set yellow *Pick up* and red *Trip* LED on local HMI in front of the IED if binary input N changes status.

Disturbance recorder

OperationM: Analog channel M is to be recorded by the disturbance recorder (*Enabled*) or not (*Disabled*).

If *OperationM* = *Disabled*, no waveform (samples) will be recorded and reported in graph. However, Trip value, pre-fault and fault value will be recorded and reported. The input channel can still be used to trig the disturbance recorder.

If *OperationM* = *Enabled*, waveform (samples) will also be recorded and reported in graph.

Event recorder

Event recorder function has no dedicated parameters.

Trip value recorder

ZeroAngleRef: The parameter defines which analog signal that will be used as phase angle reference for all other analog input signals. This signal will also be used for frequency measurement and the measured frequency is used when calculating trip values. It is suggested to point out a sampled voltage input signal, for example, a line or busbar phase voltage (channel 1-30).

Sequential of events

function has no dedicated parameters.

14.6.3.4 Consideration

The density of recording equipment in power systems is increasing, since the number of modern IEDs, where recorders are included, is increasing. This leads to a vast number of recordings at every single disturbance and a lot of information has to be handled if the recording functions do not have proper settings. The goal is to optimize the settings in each IED to be able to capture just valuable disturbances and to maximize the number that is possible to save in the IED.

The recording time should not be longer than necessary (*PostFaultrecT* and *TimeLimit*).

- Should the function record faults only for the protected object or cover more?
- How long is the longest expected fault clearing time?
- Is it necessary to include reclosure in the recording or should a persistent fault generate a second recording (*PostRetrig*)?

Minimize the number of recordings:

- Binary signals: Use only relevant signals to start the recording that is, protection trip, carrier receive and/or pickup signals.
- Analog signals: The level triggering should be used with great care, since unfortunate settings will cause enormously number of recordings. If nevertheless analog input triggering is used, chose settings by a sufficient margin from normal operation values. Phase voltages are not recommended for trigging.

Remember that values of parameters set elsewhere are linked to the information on a report. Such parameters are, for example, station and object identifiers, CT and VT ratios.

14.7 Measured value expander block MVEXP

14.7.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Measured value expander block	MVEXP	-	-

14.7.2 Application

The current and voltage measurements functions (CVMMXN, CMMXU, VMMXU and VNMMXU), current and voltage sequence measurement functions (CMSQI and VMSQI) and IEC 61850 generic communication I/O functions (MVGGIO) are provided with measurement supervision functionality. All measured values can be supervised with four settable limits, that is low-low limit, low limit, high limit and high-high limit. The measure value expander block (MVEXP) has been introduced to be able to translate the integer output signal from the measuring functions to 5 binary signals, that is below low-low limit, below low limit, normal, above high-high limit or above high limit. The output signals can be used as conditions in the configurable logic.

14.7.3 Setting guidelines

The function does not have any parameters available in Local HMI or Protection and Control IED Manager (PCM600).

GlobalBaseSel: Selects the global base value group used by the function to define (*IBase*), (*VBase*) and (*SBase*).

14.8 Station battery supervision SPVNZBAT

14.8.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Station battery supervision function	SPVNZBAT	U<>	-

14.8.2 Application

Usually, the load on the DC system is a constant resistance load, for example, lamps, LEDs, electronic instruments and electromagnetic contactors in a steady state condition. A transient RL load exists when breakers are tripped or closed.

The battery voltage has to be continuously monitored as the batteries can withstand moderate overvoltage and undervoltage only for a short period of time.

- If the battery is subjected to a prolonged or frequent overvoltage, it leads to the ageing of the battery, which may lead to the earlier failure of the battery. The other occurrences may be the thermal runaway, generation of heat or increased amount of hydrogen gas and the depletion of fluid in case of valve regulated batteries.

- If the value of the charging voltage drops below the minimum recommended float voltage of the battery, the battery does not receive sufficient charging current to offset internal losses, resulting in a gradual loss of capacity.
  - If a lead acid battery is subjected to a continuous undervoltage, heavy sulfation occurs on the plates, which leads to the loss of the battery capacity.

14.9 Insulation gas monitoring function SSIMG (63)

14.9.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Insulation gas monitoring function	SSIMG	-	63

14.9.2 Application

Insulation gas monitoring function (SSIMG ,63) is used for monitoring the circuit breaker condition. Proper arc extinction by the compressed gas in the circuit breaker is very important. When the pressure becomes too low compared to the required value, the circuit breaker operation gets blocked to minimize the risk of internal failure. Binary information based on the gas pressure in the circuit breaker is used as input signals to the function. In addition to that, the function generates alarms based on received information.

14.10 Insulation liquid monitoring function SSIML (71)

14.10.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Insulation liquid monitoring function	SSIML	-	71

14.10.2 Application

Insulation liquid monitoring function (SSIML ,71) is used for monitoring the circuit breaker condition. Proper arc extinction by the compressed oil in the circuit breaker is very important. When the level becomes too low, compared to the required value, the circuit breaker operation is blocked to minimize the risk of internal failures. Binary information based on the oil level in the circuit breaker is used as input signals to the function. In addition to that, the function generates alarms based on received information.

14.11 Circuit breaker condition monitoring SSCBR

14.11.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Circuit breaker condition monitoring	SSCBR	-	-

14.11.2 Application

SSCBR includes different metering and monitoring subfunctions.

Circuit breaker status

Circuit breaker status monitors the position of the circuit breaker, that is, whether the breaker is in an open, closed or intermediate position.

Circuit breaker operation monitoring

The purpose of the circuit breaker operation monitoring is to indicate that the circuit breaker has not been operated for a long time. The function calculates the number of days the circuit breaker has remained inactive, that is, has stayed in the same open or closed state. There is also the possibility to set an initial inactive day.

Breaker contact travel time

High travelling times indicate the need for maintenance of the circuit breaker mechanism. Therefore, detecting excessive travelling time is needed. During the opening cycle operation, the main contact starts opening. The auxiliary contact A opens, the auxiliary contact B closes, and the main contact reaches its opening position. During the closing cycle, the first main contact starts closing. The auxiliary contact B opens, the auxiliary contact A closes, and the main contact reaches its close position. The travel times are calculated based on the state changes of the auxiliary contacts and the adding correction factor to consider the time difference of the main contact's and the auxiliary contact's position change.

Operation counter

Routine maintenance of the breaker, such as lubricating breaker mechanism, is generally based on a number of operations. A suitable threshold setting, to raise an alarm when the number of operation cycle exceeds the set limit, helps preventive maintenance. This can also be used to indicate the requirement for oil sampling for dielectric testing in case of an oil circuit breaker.

The change of state can be detected from the binary input of the auxiliary contact. There is a possibility to set an initial value for the counter which can be used to initialize this functionality after a period of operation or in case of refurbished primary equipment.

Accumulation of I^yt

Accumulation of I^yt calculates the accumulated energy ΣI^yt where the factor y is known as the current exponent. The factor y depends on the type of the circuit breaker. For oil circuit breakers the factor y is normally 2. In case of a high-voltage system, the factor y can be 1.4...1.5.

Remaining life of the breaker

Every time the breaker operates, the life of the circuit breaker reduces due to wearing. The wearing in the breaker depends on the tripping current, and the remaining life of the breaker is estimated from the circuit breaker trip curve provided by the manufacturer.

Example for estimating the remaining life of a circuit breaker

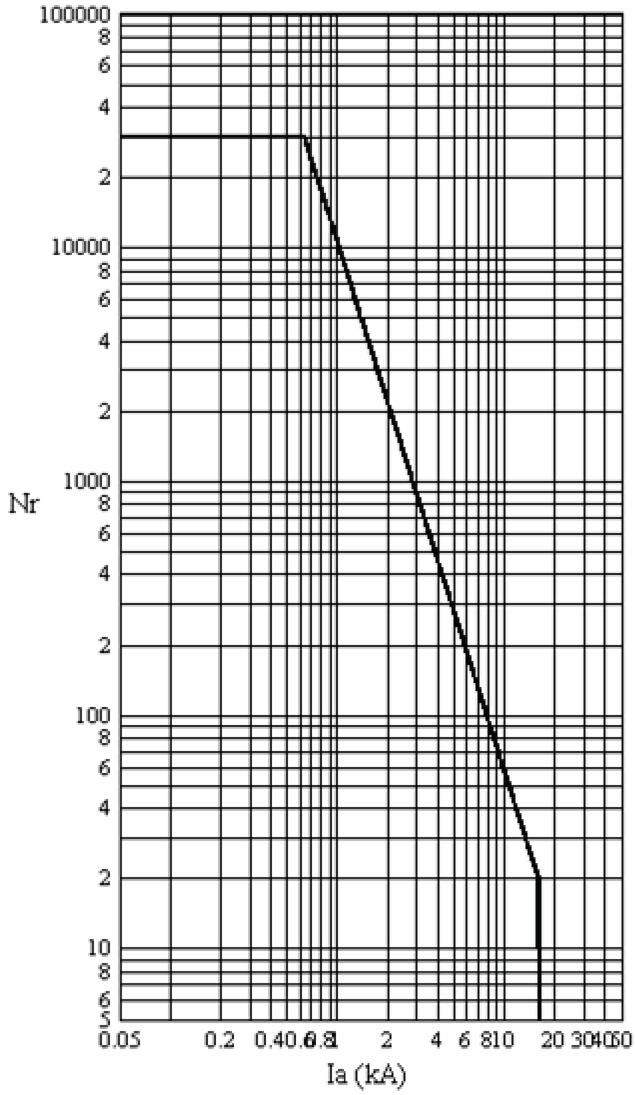


Figure 119: Trip Curves for a typical 12 kV, 630 A, 16 kA vacuum interrupter

Nr	the number of closing-opening operations allowed for the circuit breaker
Ia	the current at the time of tripping of the circuit breaker

Calculation of Directional Coefficient

The directional coefficient is calculated according to the formula:

$$Directional\ Coef = \frac{\log\left(\frac{B}{A}\right)}{\log\left(\frac{I_f}{I_r}\right)} = -2.2609$$

(Equation 85)

I_r	Rated operating current = 630 A
I_f	Rated fault current = 16 kA
A	Op number rated = 30000
B	Op number fault = 20

Calculation for estimating the remaining life

The equation shows that there are 30,000 possible operations at the rated operating current of 630 A and 20 operations at the rated fault current 16 kA. Therefore, if the tripping current is 10 kA, one operation at 10 kA is equivalent to 30,000/500=60 operations at the rated current. It is also assumed that prior to this tripping, the remaining life of the circuit breaker is 15,000 operations. Therefore, after one operation of 10 kA, the remaining life of the circuit breaker is 15,000-60=14,940 at the rated operating current.

Spring charging time indication

For normal operation of the circuit breaker, the circuit breaker spring should be charged within a specified time. Therefore, detecting long spring charging time indicates that it is time for the circuit breaker maintenance. The last value of the spring charging time can be used as a service value.

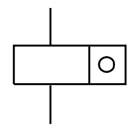
Gas pressure supervision

The gas pressure supervision monitors the gas pressure inside the arc chamber. When the pressure becomes too low compared to the required value, the circuit breaker operations are locked. A binary input is available based on the pressure levels in the function, and alarms are generated based on these inputs.

Section 15 Metering

15.1 Pulse counter PCGGIO

15.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Pulse counter	PCGGIO		-

15.1.2 Application

Pulse counter (PCGGIO) function counts externally generated binary pulses, for instance pulses coming from an external energy meter, for calculation of energy consumption values. The pulses are captured by the binary input module (BIO), and read by the PCGGIO function. The number of pulses in the counter is then reported via the station bus to the substation automation system or read via the station monitoring system as a service value. When using IEC 61850–8–1, a scaled service value is available over the station bus.

The normal use for this function is the counting of energy pulses from external energy meters. An optional number of inputs from the binary input module in IED can be used for this purpose with a frequency of up to 10 Hz. PCGGIO can also be used as a general purpose counter.

15.1.3 Setting guidelines

From PCM600, these parameters can be set individually for each pulse counter:

- *Operation*: *Disabled*/*Enabled*
- *tReporting*: *0-3600s*
- *EventMask*: *NoEvents*/*ReportEvents*

The configuration of the inputs and outputs of PCGGIO function block is made with PCM600.

On the binary input output module (BIO), the debounce filter default time is set to 5 ms, that is, the counter suppresses pulses with a pulse length less than 5 ms. The binary input channels on the binary input output module (BIO) have individual settings for debounce time, oscillation count and oscillation time. The values can be changed in the local HMI and PCM600 under **Main menu/Configuration/I/O modules**

The setting isindividual for all input channels on the binary input output module (BIO), that is, if changes of the limits are made for inputs not connected to the pulse counter, it will not influence the inputs used for pulse counting.

15.2 Energy calculation and demand handling EPTMMTR

15.2.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Energy calculation and demand handling	ETPMMTR	Wh↔	-

15.2.2 Application

Energy calculation and demand handling function ETPMMTR is intended for statistics of the forward and reverse active and reactive energy. It has a high accuracy basically given by the measurements function (CVMMXN). This function has a site calibration possibility to further increase the total accuracy.

The function is connected to the instantaneous outputs of (CVMMXN) as shown in figure 120.

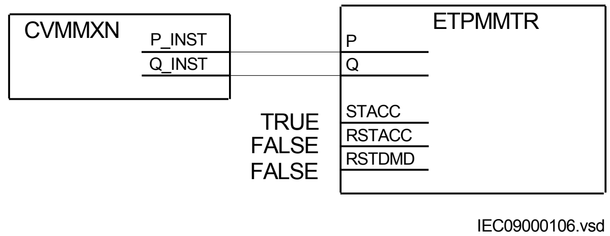


Figure 120: Connection of energy calculation and demand handling function ETPMMTR to the measurements function (CVMMXN)

The energy values can be read through communication in MWh and MVarh in monitoring tool of PCM600 and/or alternatively the values can be presented on the local HMI. The local HMI graphical display is configured with PCM600 Graphical display editor tool (GDE) with a measuring value which is selected to the active and reactive component as preferred. All four values can also be presented.

Maximum demand values are presented in MWh or MVarh in the same way.

Alternatively, the values can be presented with use of the pulse counters function (PCGGIO). The output values are scaled with the pulse output setting values *EAFAccPlsQty*, *EARAccPlsQty*, *ERFAccPlsQty* and *ERRAccPlsQty* of the energy metering function and then the pulse counter can be set-up to present the correct values by scaling in this function. Pulse counter values can then be presented on the local HMI in the same way and/or sent to the SA system through communication where the total energy then is calculated by summation of the energy pulses. This principle is good for very high values of energy as the saturation of numbers else will limit energy integration to about one year with 50 kV and 3000 A. After that the accumulation will start on zero again.

15.2.3 Setting guidelines

The parameters are set via the local HMI or PCM600.

The following settings can be done for the energy calculation and demand handling function ETPMMTR:

GlobalBaseSel: Selects the global base value group used by the function to define (*IBase*), (*VBase*) and (*SBase*).

Operation: *Disabled*/*Enabled*

tEnergy: Time interval when energy is measured.

StartAcc: *Disabled*/*Enabled* is used to switch the accumulation of energy on and off.

The input signal STACC is used to start accumulation. Input signal STACC cannot be used to halt accumulation. The energy content is reset every time STACC is activated. STACC can for example, be used when an external clock is used to switch two active energy measuring function blocks on and off to have indication of two tariffs.

tEnergyOnPls: gives the pulse length ON time of the pulse. It should be at least *100* ms when connected to the Pulse counter function block. Typical value can be *100* ms.

tEnergyOffPls: gives the OFF time between pulses. Typical value can be *100* ms.

EAFAccPlsQty and *EARAccPlsQty*: gives the MWh value in each pulse. It should be selected together with the setting of the Pulse counter (PCGGIO) settings to give the correct total pulse value.

ERFAccPlsQty and *ERRAccPlsQty*: gives the MVarh value in each pulse. It should be selected together with the setting of the Pulse counter (PCGGIO) settings to give the correct total pulse value.

For the advanced user there are a number of settings for direction, zero clamping, max limit, and so on. Normally, the default values are suitable for these parameters.

Section 16 Station communication

16.1 IEC61850-8-1 communication protocol

16.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
IEC 61850-8-1 communication protocol	IEC 61850-8-1	-	-

16.1.2 Application

IEC 61850-8-1 communication protocol allows vertical communication to HSI clients and allows horizontal communication between two or more intelligent electronic devices (IEDs) from one or several vendors to exchange information and to use it in the performance of their functions and for correct co-operation.

GOOSE (Generic Object Oriented Substation Event), which is a part of IEC 61850–8–1 standard, allows the IEDs to communicate state and control information amongst themselves, using a publish-subscribe mechanism. That is, upon detecting an event, the IED(s) use a multi-cast transmission to notify those devices that have registered to receive the data. An IED can, by publishing a GOOSE message, report its status. It can also request a control action to be directed at any device in the network.

Figure 121 shows the topology of an IEC 61850–8–1 configuration. IEC 61850–8–1 specifies only the interface to the substation LAN. The LAN itself is left to the system integrator.

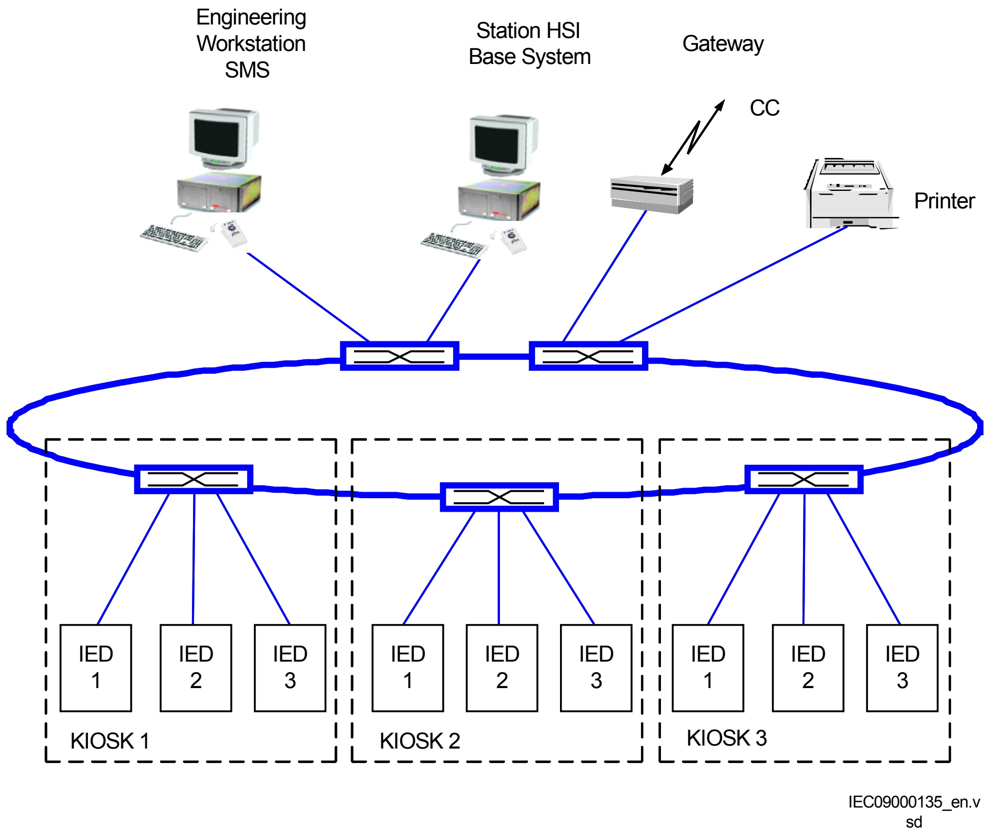


Figure 121: Example of a communication system with IEC 61850–8–1

Figure 122 shows the GOOSE peer-to-peer communication.

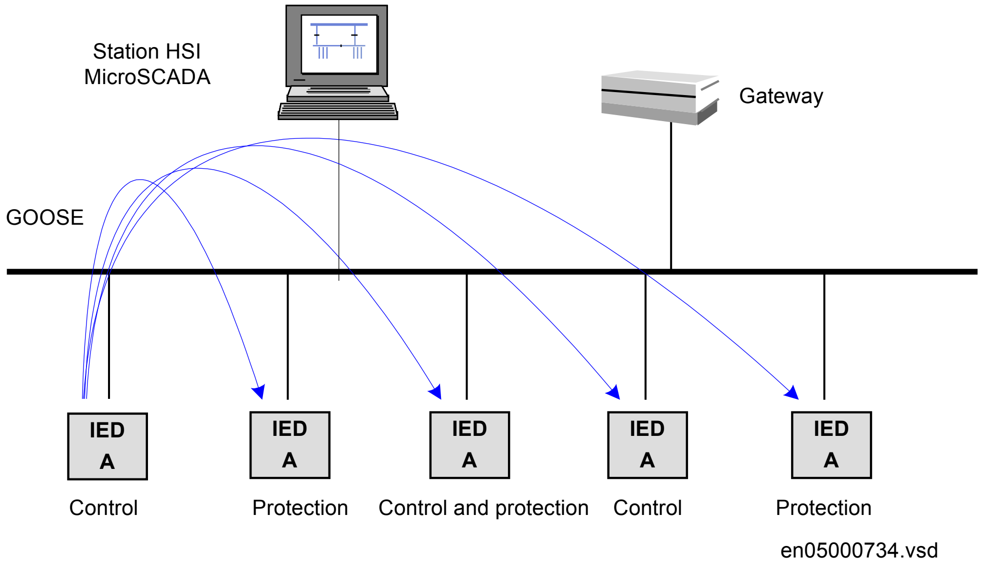


Figure 122: Example of a broadcasted GOOSE message

16.1.2.1 Horizontal communication via GOOSE

GOOSE messages are sent in horizontal communication between the IEDs. The information, which is exchanged, is used for station wide interlocking, breaker failure protection, busbar voltage selection and so on.

The simplified principle is shown in Figure 123 and can be described as follows. When IED1 has decided to transmit the data set it forces a transmission via the station bus. All other IEDs receive the data set, but only those who have this data set in their address list will take it and keep it in an input container. It is defined, that the receiving IED will take the content of the received data set and makes it available for the application configuration.

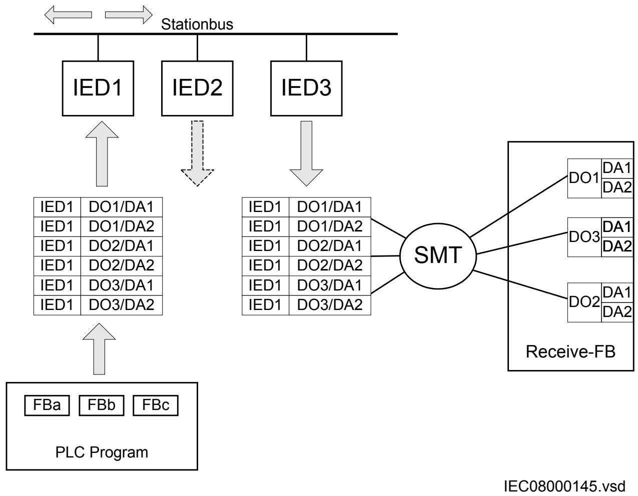
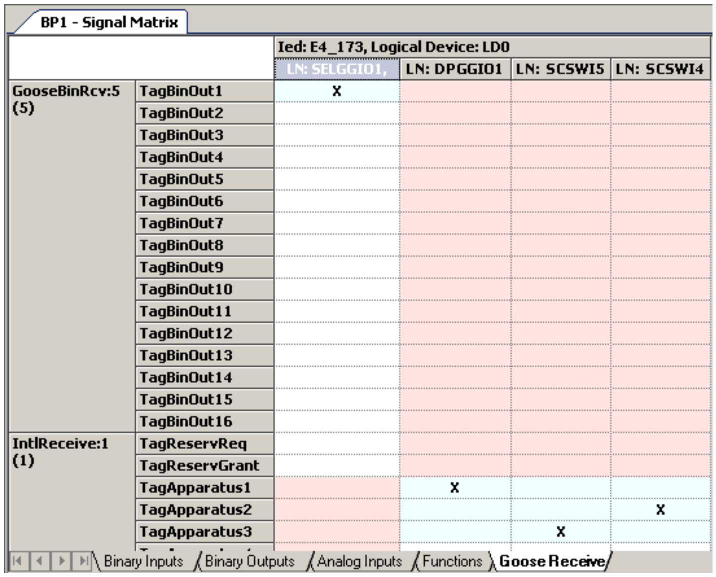


Figure 123: SMT: GOOSE principle and signal routing with SMT

Special function blocks take the data set and present it via the function block as output signals for application functions in the application configuration. Different GOOSE receive function blocks are available for the specific tasks.

SMT links the different data object attributes (for example stVal or magnitude) to the output signal to make it available for functions in the application configuration. When a matrix cell array is marked red the IEC 61850–8–1 data attribute type does not fit together, even if the GOOSE receive function block is the partner. SMT checks this on the content of the received data set. See Figure 124



IEC08000174.vsd

Figure 124: SMT: GOOSE marshalling with SMT

GOOSE receive function blocks extract process information, received by the data set, into single attribute information that can be used within the application configuration. Crosses in the SMT matrix connect received values to the respective function block signal in SMT, see Figure 125

The corresponding quality attribute is automatically connected by SMT. This quality attribute is available in ACT, through the outputs of the available GOOSE function blocks.

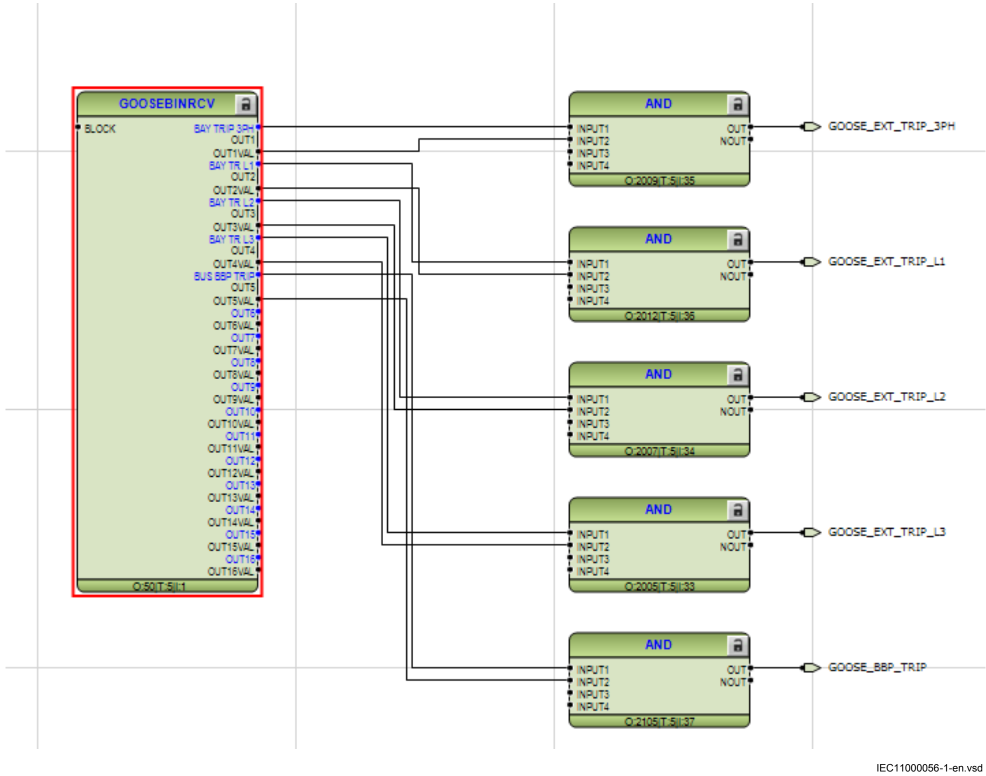


Figure 125: SMT: GOOSE receive function block with converted signals

16.1.3 Setting guidelines

There are two settings related to the IEC 61850–8–1 protocol:

Operation User can set IEC 61850 communication to *Enabled* or *Disabled*.

GOOSE has to be set to the Ethernet link where GOOSE traffic shall be send and received.

IEC 61850–8–1 specific data (logical nodes etc.) per included function in an IED can be found in the communication protocol manual for IEC 61850–8–1.

16.2 DNP3 protocol

DNP3 (Distributed Network Protocol) is a set of communications protocols used to communicate data between components in process automation systems. For a detailed description of the DNP3 protocol, see the DNP3 Communication protocol manual.

16.3 IEC 60870-5-103 communication protocol

IEC 60870-5-103 is an unbalanced (master-slave) protocol for coded-bit serial communication exchanging information with a control system, and with a data transfer rate up to 19200 bit/s. In IEC terminology, a primary station is a master and a secondary station is a slave. The communication is based on a point-to-point principle. The master must have software that can interpret IEC 60870-5-103 communication messages.

The Communication protocol manual for IEC 60870-5-103 includes the 650 series vendor specific IEC 60870-5-103 implementation.

IEC 60870-5-103 protocol can be configured to use either the optical serial or RS485 serial communication interface on the COM05 communication module. The functions Operation selection for optical serial (OPTICALPROT) and Operation selection for RS485 (RS485PROT) are used to select the communication interface.

See the Engineering manual for IEC103 60870-5-103 engineering procedures in PCM600.

The functions IEC60870-5-103 Optical serial communication (OPTICAL103) and IEC60870-5-103 serial communication for RS485 (RS485103) are used to configure the communication parameters for either the optical serial or RS485 serial communication interfaces.

Section 17 Basic IED functions

17.1 Self supervision with internal event list

17.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Internal error signal	INTERRSIG	-	-
Internal event list	SELFSUPEVLST	-	-

17.1.2 Application

The protection and control IEDs have many functions included . Self supervision with internal event list (SELFSUPEVLST) and internal error signals (INTERRSIG) function provide supervision of the IED. The fault signals make it easier to analyze and locate a fault.

Both hardware and software supervision is included and it is also possible to indicate possible faults through a hardware contact on the power supply module and/or through the software communication.

Internal events are generated by the built-in supervisory functions. The supervisory functions supervise the status of the various modules in the IED and, in case of failure, a corresponding event is generated. Similarly, when the failure is corrected, a corresponding event is generated.

The event list is updated every 10s hence, an event will not be visible in the event list as soon as it is created.

Apart from the built-in supervision of the various modules, events are also generated when the status changes for the:

- built-in real time clock (in operation/out of order).
- external time synchronization (in operation/out of order).
- Change lock (on/off)

Events are also generated:

- whenever any setting in the IED is changed.

The internal events are time tagged with a resolution of 1 ms and stored in a list. The list can store up to 40 events. The list is based on the FIFO principle, that is, when it is full, the oldest event is overwritten. The list can be cleared via the local HMI .

The list of internal events provides valuable information, which can be used during commissioning and fault tracing.

17.2 Time synchronization

17.2.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Time synchronization	TIMESYNCHGEN	-	-

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Time system, summer time begins	DSTBEGIN	-	-

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Time system, summer time ends	DSTEND	-	-

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Time synchronization via IRIG-B	IRIG-B	-	-

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Time synchronization via SNTP	SNTP	-	-

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Time zone from UTC	TIMEZONE	-	-

17.2.2 Application

Use a common global source for example GPS time synchronization inside each substation as well as inside the area of the utility responsibility to achieve a common time base for the IEDs in a protection and control system. This makes comparison and analysis of events and disturbance data between all IEDs in the power system possible.

Time-tagging of internal events and disturbances are an excellent help when evaluating faults. Without time synchronization, only the events within the IED can be compared to one another. With time synchronization, events and disturbances within the entire station, and even between line ends, can be compared during evaluation.

In the IED, the internal time can be synchronized from a number of sources:

- SNTP
- IRIG-B
- DNP
- IEC60870-5-103

Micro SCADA OPC server should not be used as a time synchronization source.

17.2.3 Setting guidelines

System time

The time is only possible to set inside the IED via the local HMI by navigating to **Configuration/Time/SYSTEMTIME** with year, month, day, hour, minute and second.

Synchronization

With external time synchronization the setting how to synchronize for the real-time clock (TIME) are set via local HMI or PCM600.

TimeSynch

The setting *TIMESYNCGEN* is used to set the source of the time synchronization. The setting alternatives are:

CoarseSyncSrc which can have the following values:

- *Disabled*
- *SNTP*
- *DNP*
- *IEC60870-5-103*

FineSyncSource which can have the following values:

- *Disabled*
- *SNTP*
- *IRIG-B*

The parameter *SyncMaster* defines if the IED is a master, or not a master for time synchronization in a system of IEDs connected in a communication network (IEC61850-8-1). The *SyncMaster* can have the following values:

- *Disabled*
- *SNTP -Server*

The time synchronization fine tunes the clock.

IEC 60870-5-103 time synchronization

An IED with IEC 60870-5-103 protocol can be used for time synchronization, but for accuracy reasons, it is not recommended. In some cases, however, this kind of synchronization is needed, for example, when no other synchronization is available.

First, set the IED to be synchronized via IEC 60870-5-103 either from **IED Configuration/Time/Synchronization/TIMESYNCHGEN:1** in PST or from the local HMI.

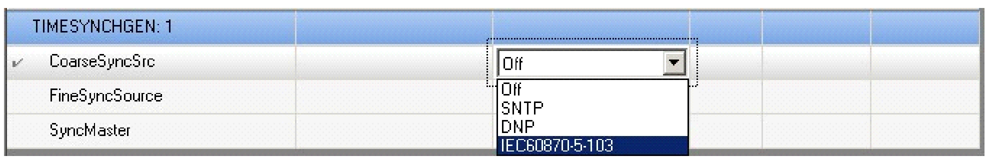


Figure 126: Settings under TIMESYNCHGEN:1 in PST

Only *CoarseSyncSrc* can be set to IEC 60870-5-103, not *FineSyncSource*.

After setting up the time synchronization source, the user must check and modify the IEC 60870-5-103 time synchronization specific settings, under: **IED Configuration/ Communication/Station communication/IEC60870-5-103:1**.

- *MasterTimeDomain* specifies the format of the time sent by the master. Format can be:

    - Coordinated Universal Time (*UTC*)
    - Local time set in the master (*Local*)
    - Local time set in the master adjusted according to daylight saving time (*Local with DST*)
- *TimeSyncMode* specifies the time sent by the IED. The time synchronisation is done using the following ways:
    - *IEDTime*: The IED sends the messages with its own time.
    - *LinMasTime*: The IED measures the offset between its own time and the master time, and applies the same offset for the messages sent as in the *IEDTimeSkew*. But in *LinMasTime* it applies the time changes occurred between two synchronised messages.
    - *IEDTimeSkew*: The IED measures the offset in between its own time and the master time and applies the same offset for the messages sent.
- *EvalTimeAccuracy* evaluates time accuracy for invalid time. Specifies the accuracy of the synchronization (5, 10, 20 or 40 ms). If the accuracy is less than the specified value, the “Bad Time” flag is raised. To accommodate those masters that are really bad in time sync, the *EvalTimeAccuracy* can be set to *Disabled*.

According to the standard, the “Bad Time” flag is reported when synchronization has been omitted in the protection for >23 h.

17.3 Parameter setting group handling

17.3.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Setting group handling	SETGRPS	-	-
Parameter setting groups	ACTVGRP	-	-

17.3.2 Application

Four different groups of settings are available to optimize IED operation for different power system conditions. By creating and switching between fine tuned setting sets, either from the local HMI or configurable binary inputs, results in a highly adaptable IED that can cope with a variety of power system scenarios.

Different conditions in networks with different voltage levels require highly adaptable protection and control IEDs to best provide for dependability, security and selectivity requirements. Protection IEDs operate with a higher degree of availability, especially,

if the setting values of their parameters are continuously optimized according to the conditions in the power system.

Operational departments can plan for different operating conditions in the primary power system equipment. The protection engineer can prepare the necessary optimized and pre-tested settings in advance for different protection functions.

The four different groups of setting parameters are available in the IED. Any of them can be activated through different inputs by means of external programmable binary or internal control signals.

17.3.3 Setting guidelines

The setting *ActiveSetGrp*, is used to select which parameter group to be active. The active group can also be selected with configured input to the function block ACTVGRP.

The parameter *MaxNoSetGrp* defines the maximum number of setting groups in use to switch between. Only the selected number of setting groups will be available in the Parameter Setting tool (PST) for activation with the ACTVGRP function block.

17.4 Test mode functionality TESTMODE

17.4.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Test mode functionality	TESTMODE	-	-

17.4.2 Application

The protection and control IEDs may have a complex configuration with many included functions. To make the testing procedure easier, the IEDs include the feature that allows individual blocking of all functions except the function(s) the shall be tested.

This means that it is possible to see when a function is activated or trips. It also enables the user to follow the operation of several related functions to check correct functionality and to check parts of the configuration, and so on.

17.4.3 Setting guidelines

There are two possible ways to place the IED in the *TestMode= Enabled*" state. This means that if the IED is set to normal operation (*TestMode* = *Disabled*), but the functions are still shown being in the test mode, the input signal INPUT on the TESTMODE function block must be activated in the configuration.

Forcing of binary output signals is only possible when the IED is in test mode.

17.5 Change lock CHNGLCK

17.5.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Change lock function	CHNGLCK	-	-

17.5.2 Application

Change lock function CHNGLCK is used to block further changes to the IED configuration once the commissioning is complete. The purpose is to make it impossible to perform inadvertent IED configuration and setting changes.

However, when activated, CHNGLCK will still allow the following actions that does not involve reconfiguring of the IED:

- Monitoring
- Reading events
- Resetting events
- Reading disturbance data
- Clear disturbances
- Reset LEDs
- Reset counters and other runtime component states
- Control operations
- Set system time
- Enter and exit from test mode
- Change of active setting group

The binary input controlling the function is defined in ACT or SMT. The CHNGLCK function is configured using ACT.

LOCK	Binary input signal that will activate/deactivate the function, defined in ACT or SMT.
ACTIVE	Output status signal
OVERRIDE	Set if function is overridden

When CHNGLCK has a logical one on its input, then all attempts to modify the IED configuration and setting will be denied and the message "Error: Changes blocked" will be displayed on the local HMI; in PCM600 the message will be "Operation denied by active ChangeLock". The CHNGLCK function should be configured so that it is controlled by a signal from a binary input card. This guarantees that by setting that signal to a logical zero, CHNGLCK is deactivated. If any logic is included in the signal path to the CHNGLCK input, that logic must be designed so that it cannot permanently issue a logical one to the CHNGLCK input. If such a situation would occur in spite of these precautions, then please contact the local ABB representative for remedial action.

17.5.3 Setting guidelines

The Change lock function CHNGLCK does not have any parameters available in the local HMI or PCM600.

17.6 IED identifiers TERMINALID

17.6.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
IED identifiers	TERMINALID	-	-

17.6.2 Application

17.6.2.1 Customer specific settings

The customer specific settings are used to give the IED a unique name and address. The settings are used by a central control system to communicate with the IED. The customer specific identifiers are found in the local HMI under **Configuration/Power system/Identifiers/TERMINALID**

The settings can also be made from PCM600. For more information about the available identifiers, see the technical manual.

Use only characters A - Z, a - z and 0 - 9 in station, unit and object names.

17.7 Product information PRODINF

17.7.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Product information	PRODINF	-	-

17.7.2 Application

17.7.2.1 Factory defined settings

The factory defined settings are very useful for identifying a specific version and very helpful in the case of maintenance, repair, interchanging IEDs between different Substation Automation Systems and upgrading. The factory made settings can not be changed by the customer. They can only be viewed. The settings are found in the local HMI under **Main menu/Diagnostics/IED status/Product identifiers**

The following identifiers are available:

- IEDProdType
  - Describes the type of the IED (like REL, REC or RET). Example: *REL650*
- ProductVer
  - Describes the product version. Example: *1.2.3*

1	is the Major version of the manufactured product this means, new platform of the product
2	is the Minor version of the manufactured product this means, new functions or new hardware added to the product
3	is the Major revision of the manufactured product this means, functions or hardware is either changed or enhanced in the product

- ProductDef
  - Describes the release number, from the production. Example: *1.2.3.4* where;

1	is the Major version of the manufactured product this means, new platform of the product
2	is the Minor version of the manufactured product this means, new functions or new hardware added to the product

3	is the Major revision of the manufactured product this means, functions or hardware is either changed or enhanced in the product
4	is the Minor revision of the manufactured product this means, code is corrected in the product

- SerialNo: the structure of the SerialNo is as follows, for example, T0123456 where

01	is the last two digits in the year when the IED was manufactured that is, 2001
23	is the week number when the IED was manufactured
456	is the sequential number of the IEDs produced during the production week

- OrderingNo: the structure of the OrderingNo is as follows, for example, 1MRK008526-BA. This alphanumeric string has no specific meaning except, that it is used for internal identification purposes within ABB.
- ProductionDate: states the production date in the “YYYY-MM_DD” format.

17.8 Primary system values PRIMVAL

17.8.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Primary system values	PRIMVAL	-	-

17.8.2 Application

The rated system frequency and phasor rotation are set under **Main menu/ Configuration/ Power system/ Primary values/PRIMVAL** in the local HMI and PCM600 parameter setting tree.

17.9 Signal matrix for analog inputs SMAI

17.9.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Signal matrix for analog inputs	SMAI_20_x	-	-

17.9.2 Application

Signal matrix for analog inputs function (SMAI), also known as the preprocessor function, processes the analog signals connected to it and gives information about all aspects of the analog signals connected, like the RMS value, phase angle, frequency, harmonic content, sequence components and so on. This information is then used by the respective functions in ACT (for example protection, measurement or monitoring).

The SMAI function is used within PCM600 in direct relation with the Signal Matrix tool or the Application Configuration tool.

The SMAI function blocks for the 650 series of products are possible to set for two cycle times either 5 or 20ms. The function blocks connected to a SMAI function block shall always have the same cycle time as the SMAI block.

17.9.3 Setting guidelines

The parameters for the signal matrix for analog inputs (SMAI) functions are set via the local HMI or via the PCM600.

Every SMAI function block can receive four analog signals (three phases and one neutral value), either voltage or current. SMAI outputs give information about every aspect of the 3ph analog signals acquired (phase angle, RMS value, frequency and frequency derivates, and so on – 244 values in total). Besides the block “group name”, the analog inputs type (voltage or current) and the analog input names that can be set directly in ACT.

GlobalBaseSel: Selects the global base value group used by the function to define (*IBase*), (*VBase*) and (*SBase*).

DFTRefExtOut: Parameter valid only for function block SMAI_20_1:1, SMAI_20_1:2 and SMAI_80_1 .

These 3 SMAI blocks can be used as reference blocks for other SMAI blocks when the output signal SPFCOUT is used for relating other SMAI blocks to a common phase reference block for external output (SPFCOUT function output).

DFTReference: Reference DFT for the block.

These DFT reference block settings decide DFT reference for DFT calculations. The settings *InternalDFTRef* will use fixed DFT reference based on set system frequency. The setting *DFTRefGrpn* (where n is a number from 1 to 12) will use DFT reference from the selected group block numbered n, when own group selected adaptive DFT

reference will be used based on calculated signal frequency from own group. The setting *ExternalDFTRef* will use reference based on what is connected to input DFTSPFC.

ConnectionType: Connection type for that specific instance (n) of the SMAI (if it is *Ph-N* or *Ph-Ph*). Depending on connection type setting the not connected *Ph-N* or *Ph-Ph* outputs will be calculated.

Negation: Negation means rotation with 180^0 of the vectors. If the user wants to negate the 3ph signal, it is possible to choose to negate only the phase signals *Negate3Ph*, only the neutral signal *NegateN* or both *Negate3Ph+N*.

MinValFreqMeas: The minimum value of the voltage for which the frequency is calculated, expressed as percent of the voltage in the selected Global Base voltage group (n) (for each instance 1<n<6).

Settings *DFTRefExtOut* and *DFTReference* shall be set to default value *InternalDFTRef* if no VT inputs are available.

Even if the user sets the *AnalogInputType* of a SMAI block to “*Current*”, the *MinValFreqMeas* is still visible. However, using the current channel values as base for frequency measurement is **not recommendable** for a number of reasons, not last among them being the low level of currents that one can have in normal operating conditions.

Example of adaptive frequency tracking

Task time group 1	
SMAI instance	**3 phase group**
SMAI_20_1:1	1
SMAI_20_2:1	2
SMAI_20_3:1	3
SMAI_20_4:1	4
SMAI_20_5:1	5
SMAI_20_6:1	6
SMAI_20_7:1	7
SMAI_20_8:1	8
SMAI_20_9:1	9
SMAI_20_10:1	10
SMAI_20_11:1	11
SMAI_20_12:1	12

DFTRefGrp7

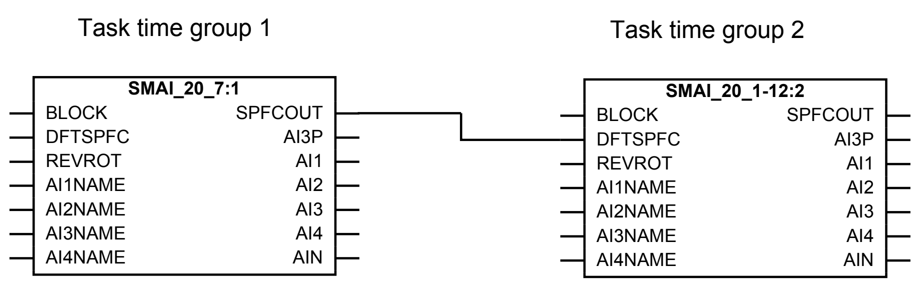
Task time group 2	
SMAI instance	**3 phase group**
SMAI_20_1:2	1
SMAI_20_2:2	2
SMAI_20_3:2	3
SMAI_20_4:2	4
SMAI_20_5:2	5
SMAI_20_6:2	6
SMAI_20_7:2	7
SMAI_20_8:2	8
SMAI_20_9:2	9
SMAI_20_10:2	10
SMAI_20_11:2	11
SMAI_20_12:2	12

IEC09000029_1_en.vsd

Figure 127: SMAI instances as organized in different task time groups and the corresponding parameter numbers

The example shows a situation with adaptive frequency tracking with one reference selected for all instances. In practice each instance can be adapted to the needs of the actual application.

Example 1



IEC09000028-1.vsd

Figure 128: Configuration for using an instance in task time group 1 as DFT reference

Assume instance SMAI_20_7:1 in task time group 1 has been selected in the configuration to control the frequency tracking (For the SMAI_20_x task time groups). Observe that the selected reference instance (i.e. frequency tracking master) must be a voltage type. Observe that positive sequence voltage is used for the frequency tracking feature.

For task time group 1 this gives the following settings (see Figure 127 for numbering):

SMAI_20_7:1: *DFTRefExtOut* = *DFTRefGrp7* to route SMAI_20_7:1 reference to the SPFCOUT output, *DFTReference* = *DFTRefGrp7* for SMAI_20_7:1 to use SMAI_20_7:1 as reference (see Figure 128). .

SMAI_20_2:1 - SMAI_20_12:1 *DFTReference* = *DFTRefGrp7* for SMAI_20_2:1 - SMAI_20_12:1 to use SMAI_20_7:1 as reference.

For task time group 2 this gives the following settings:

SMAI_20_1:2 - SMAI_20_12:2 *DFTReference* = *ExternalDFTRef* to use DFTSPFC input as reference (SMAI_20_7:1)

17.10 Summation block 3 phase 3PHSUM

17.10.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Summation block 3 phase	3PHSUM	-	-

17.10.2 Application

Summation block 3 phase function 3PHSUM is used to get the sum of two sets of three-phase analog signals (of the same type) for those IED functions that might need it.

17.10.3 Setting guidelines

The summation block receives the three-phase signals from SMAI blocks. The summation block has several settings.

GlobalBaseSel: Selects the global base value group used by the function to define (*IBase*), (*VBase*) and (*SBase*).

SummationType: Summation type (*Group 1 + Group 2*, *Group 1 - Group 2*, *Group 2 - Group 1* or *–(Group 1 + Group 2)*).

DFTReference: The reference DFT block (*InternalDFT Ref*,*DFTRefGrp1* or *External DFT ref*) .

FreqMeasMinVal: The minimum value of the voltage for which the frequency is calculated, expressed as percent of *VBase* (for each instance x).

17.11 Global base values GBASVAL

17.11.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Global base values	GBASVAL	-	-

17.11.2 Application

Global base values function (GBASVAL) is used to provide global values, common for all applicable functions within the IED. One set of global values consists of values for current, voltage and apparent power and it is possible to have six different sets.

This is an advantage since all applicable functions in the IED use a single source of base values. This facilitates consistency throughout the IED and also facilitates a single point for updating values when necessary.

Each applicable function in the IED has a parameter, *GlobalBaseSel*, defining one out of the six sets of GBASVAL functions.

17.11.3 Setting guidelines

VBase: Phase-to-phase voltage value to be used as a base value for applicable functions throughout the IED.

IBase: Phase current value to be used as a base value for applicable functions throughout the IED.

SBase: Standard apparent power value to be used as a base value for applicable functions throughout the IED, typically $SBase=\sqrt{3} \cdot VBase \cdot IBase$.

17.12 Authority check ATHCHCK

17.12.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Authority check	ATHCHCK	-	-

17.12.2 Application

To safeguard the interests of our customers, both the IED and the tools that are accessing the IED are protected, by means of authorization handling. The authorization handling of the IED and the PCM600 is implemented at both access points to the IED:

- local, through the local HMI
- remote, through the communication ports

17.12.2.1 Authorization handling in the IED

At delivery the default user is the SuperUser. No Log on is required to operate the IED until a user has been created with the IED User Management..

Once a user is created and written to the IED, that user can perform a Log on, using the password assigned in the tool. Then the default user will be Guest.

If there is no user created, an attempt to log on will display a message box: “No user defined!”

If one user leaves the IED without logging off, then after the timeout (set in **Main menu/Configuration/HMI/Screen/1:SCREEN**) elapses, the IED returns to Guest state, when only reading is possible. By factory default, the display timeout is set to 60 minutes.

If one or more users are created with the IED User Management and written to the IED, then, when a user attempts a Log on by pressing the key or when the user attempts to perform an operation that is password protected, the Log on window opens.

The cursor is focused on the User identity field, so upon pressing the key, one can change the user name, by browsing the list of users, with the “up” and “down” arrows. After choosing the right user name, the user must press the key again. When it comes to password, upon pressing the key, the following characters will show up:

"✳✳✳✳✳✳✳✳". The user must scroll for every letter in the password. After all the letters are introduced (passwords are case sensitive) choose OK and press the ↵ key again.

At successful Log on, the local HMI shows the new user name in the status bar at the bottom of the LCD. If the Log on is OK, when required to change for example a password protected setting, the local HMI returns to the actual setting folder. If the Log on has failed, an "Error Access Denied" message opens. If a user enters an incorrect password three times, that user will be blocked for ten minutes before a new attempt to log in can be performed. The user will be blocked from logging in, both from the local HMI and PCM600. However, other users are to log in during this period.

17.13 Authority status ATHSTAT

17.13.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Authority status	ATHSTAT	-	-

17.13.2 Application

Authority status (ATHSTAT) function is an indication function block, which informs about two events related to the IED and the user authorization:

- the fact that at least one user has tried to log on wrongly into the IED and it was blocked (the output USRBLKED)
- the fact that at least one user is logged on (the output LOGGEDON)

The two outputs of ATHSTAT function can be used in the configuration for different indication and alarming reasons, or can be sent to the station control for the same purpose.

17.14 Denial of service

17.14.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Denial of service, frame rate control for front port	DOSFRNT	-	-

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Denial of service, frame rate control for LAN1 port	DOSLAN1	-	-

17.14.2 Application

The denial of service functions (DOSFRNT,DOSLAN1 and DOSSCKT) are designed to limit the CPU load that can be produced by Ethernet network traffic on the IED. The communication facilities must not be allowed to compromise the primary functionality of the device. All inbound network traffic will be quota controlled so that too heavy network loads can be controlled. Heavy network load might for instance be the result of malfunctioning equipment connected to the network.

DOSFRNT, DOSLAN1 and DOSSCKT measures the IED load from communication and, if necessary, limit it for not jeopardizing the IEDs control and protection functionality due to high CPU load. The function has the following outputs:

- LINKUP indicates the Ethernet link status
- WARNING indicates that communication (frame rate) is higher than normal
- ALARM indicates that the IED limits communication

17.14.3 Setting guidelines

The function does not have any parameters available in the local HMI or PCM600.

Section 18 Requirements

18.1 Current transformer requirements

The performance of a protection function will depend on the quality of the measured current signal. Saturation of the current transformer (CT) will cause distortion of the current signal and can result in a failure to operate or cause unwanted operations of some functions. Consequently CT saturation can have an influence on both the dependability and the security of the protection. This protection IED has been designed to permit heavy CT saturation with maintained correct operation.

18.1.1 Current transformer classification

To guarantee correct operation, the current transformers (CTs) must be able to correctly reproduce the current for a minimum time before the CT will begin to saturate. To fulfill the requirement on a specified time to saturation the CTs must fulfill the requirements of a minimum secondary e.m.f. that is specified below.

There are several different ways to specify CTs. Conventional magnetic core CTs are usually specified and manufactured according to some international or national standards, which specify different protection classes as well. There are many different standards and a lot of classes but fundamentally there are three different types of CTs:

- High remanence type CT
- Low remanence type CT
- Non remanence type CT

The high remanence type has no limit for the remanent flux. This CT has a magnetic core without any airgap and a remanent flux might remain almost infinite time. In this type of transformers the remanence can be up to around 80% of the saturation flux. Typical examples of high remanence type CT are class P, PX, TPS, TPX according to IEC, class P, X according to BS (old British Standard) and non gapped class C, K according to ANSI/IEEE.

The low remanence type has a specified limit for the remanent flux. This CT is made with a small air gap to reduce the remanence to a level that does not exceed 10% of the saturation flux. The small air gap has only very limited influences on the other properties of the CT. Class PR, TPY according to IEC are low remanence type CTs.

The non remanence type CT has practically negligible level of remanent flux. This type of CT has relatively big air gaps in order to reduce the remanence to practically zero level. In the same time, these air gaps reduce the influence of the DC-component from the primary fault current. The air gaps will also decrease the measuring accuracy in the non-saturated region of operation. Class TPZ according to IEC is a non remanence type CT.

Different standards and classes specify the saturation e.m.f. in different ways but it is possible to approximately compare values from different classes. The rated equivalent limiting secondary e.m.f. E_{al} according to the IEC 60044 – 6 standard is used to specify the CT requirements for the IED. The requirements are also specified according to other standards.

18.1.2 Conditions

The requirements are a result of investigations performed in our network simulator. The current transformer models are representative for current transformers of high remanence and low remanence type. The results may not always be valid for non remanence type CTs (TPZ).

The performances of the protection functions have been checked in the range from symmetrical to fully asymmetrical fault currents. Primary time constants of at least 120 ms have been considered at the tests. The current requirements below are thus applicable both for symmetrical and asymmetrical fault currents.

Depending on the protection function phase-to-ground, phase-to-phase and three-phase faults have been tested for different relevant fault positions for example, close in forward and reverse faults, zone 1 reach faults, internal and external faults. The dependability and security of the protection was verified by checking for example, time delays, unwanted operations, directionality, overreach and stability.

The remanence in the current transformer core can cause unwanted operations or minor additional time delays for some protection functions. As unwanted operations are not acceptable at all maximum remanence has been considered for fault cases critical for the security, for example, faults in reverse direction and external faults. Because of the almost negligible risk of additional time delays and the non-existent risk of failure to operate the remanence have not been considered for the dependability cases. The requirements below are therefore fully valid for all normal applications.

It is difficult to give general recommendations for additional margins for remanence to avoid the minor risk of an additional time delay. They depend on the performance and economy requirements. When current transformers of low remanence type (for example, TPY, PR) are used, normally no additional margin is needed. For current transformers of high remanence type (for example, P, PX, TPS, TPX) the small probability of fully asymmetrical faults, together with high remanence in the same

direction as the flux generated by the fault, has to be kept in mind at the decision of an additional margin. Fully asymmetrical fault current will be achieved when the fault occurs at approximately zero voltage (0°). Investigations have shown that 95% of the faults in the network will occur when the voltage is between 40° and 90°. In addition fully asymmetrical fault current will not exist in all phases at the same time.

18.1.3 Fault current

The current transformer requirements are based on the maximum fault current for faults in different positions. Maximum fault current will occur for three-phase faults or single phase-to-ground faults. The current for a single phase-to-ground fault will exceed the current for a three-phase fault when the zero sequence impedance in the total fault loop is less than the positive sequence impedance.

When calculating the current transformer requirements, maximum fault current for the relevant fault position should be used and therefore both fault types have to be considered.

18.1.4 Secondary wire resistance and additional load

The voltage at the current transformer secondary terminals directly affects the current transformer saturation. This voltage is developed in a loop containing the secondary wires and the burden of all relays in the circuit. For ground faults the loop includes the phase and neutral wire, normally twice the resistance of the single secondary wire. For three-phase faults the neutral current is zero and it is just necessary to consider the resistance up to the point where the phase wires are connected to the common neutral wire. The most common practice is to use four wires secondary cables so it normally is sufficient to consider just a single secondary wire for the three-phase case.

The conclusion is that the loop resistance, twice the resistance of the single secondary wire, must be used in the calculation for phase-to-ground faults and the phase resistance, the resistance of a single secondary wire, may normally be used in the calculation for three-phase faults.

As the burden can be considerable different for three-phase faults and phase-to-ground faults it is important to consider both cases. Even in a case where the phase-to-ground fault current is smaller than the three-phase fault current the phase-to-ground fault can be dimensioning for the CT depending on the higher burden.

In isolated or high impedance grounded systems the phase-to-ground fault is not the dimensioning case and therefore the resistance of the single secondary wire always can be used in the calculation, for this case.

18.1.5 General current transformer requirements

The current transformer ratio is mainly selected based on power system data for example, maximum load. However, it should be verified that the current to the protection is higher than the minimum operating value for all faults that are to be detected with the selected CT ratio. The minimum operating current is different for different functions and normally settable so each function should be checked.

The current error of the current transformer can limit the possibility to use a very sensitive setting of a sensitive residual overcurrent protection. If a very sensitive setting of this function will be used it is recommended that the current transformer should have an accuracy class which have an current error at rated primary current that is less than ±1% (for example, 5P). If current transformers with less accuracy are used it is advisable to check the actual unwanted residual current during the commissioning.

18.1.6 Rated equivalent secondary e.m.f. requirements

With regard to saturation of the current transformer all current transformers of high remanence and low remanence type that fulfill the requirements on the rated equivalent secondary e.m.f. E_{al} below can be used. The characteristic of the non remanence type CT (TPZ) is not well defined as far as the phase angle error is concerned. If no explicit recommendation is given for a specific function we therefore recommend contacting ABB to confirm that the non remanence type can be used.

The CT requirements for the different functions below are specified as a rated equivalent limiting secondary e.m.f. E_{al} according to the IEC 60044-6 standard. Requirements for CTs specified in different ways are given at the end of this section.

18.1.6.1 Transformer differential protection

The current transformers must have a rated equivalent secondary e.m.f. E_{al} that is larger than the maximum of the required secondary e.m.f. E_{alreq} below:

$$E_{al} \geq E_{alreq} = 30 \cdot I_{nt} \cdot \frac{I_{sn}}{I_{pn}} \cdot \left(R_{CT} + R_L + \frac{S_R}{I_n^2} \right)$$

(Equation 86)

$$E_{al} \geq E_{alreq} = 2 \cdot I_{tf} \cdot \frac{I_{sn}}{I_{pn}} \cdot \left(R_{CT} + R_L + \frac{S_R}{I_n^2} \right)$$

(Equation 87)

where:

I_{nt}	The rated primary current of the power transformer (A)
I_{tf}	Maximum primary fundamental frequency current that passes two main CTs and the power transformer (A)
I_{pn}	The rated primary CT current (A)
I_{sn}	The rated secondary CT current (A)
I_n	The nominal current of the protection IED (A)
R_{CT}	The secondary resistance of the CT (Ω)
R_L	The resistance of the secondary wire and additional load (Ω). The loop resistance containing the phase and neutral wires must be used for faults in solidly grounded systems. The resistance of a single secondary wire should be used for faults in high impedance grounded systems.
S_R	The burden of an IED current input channel (VA). S_R=0.010 VA/channel for I_r=1 A and S_r=0.250 VA/channel for I_r=5 A

In substations with breaker-and-a-half or double-busbar double-breaker arrangement, the fault current may pass two main CTs for the transformer differential protection without passing the power transformer. In such cases and if both main CTs have equal ratios and magnetization characteristics the CTs must satisfy equation 86 and equation 88.

$$E_{al} \geq E_{alreq} = I_f \cdot \frac{I_{sn}}{I_{pn}} \cdot \left(R_{CT} + R_L + \frac{S_R}{I_n^2} \right)$$

(Equation 88)

where:

I_f	Maximum primary fundamental frequency current that passes two main CTs without passing the power transformer (A)

18.1.6.2 1 Ph high impedance differential protection

The CTs connected to the IED must have a rated equivalent secondary e.m.f. E_{al} that is larger than or equal to the required equivalent secondary e.m.f. E_{alreq} below:

$$E_{al} \geq E_{alreq} = 2 \cdot V_s = 2 \cdot I_{tmax} \cdot \frac{I_{sn}}{I_{pn}} \cdot (R_{CT} + R_L)$$

(Equation 89)

where:

V_s	Set operate value to the voltage relay (V)
I_{kmax}	Maximum primary fundamental frequency fault current for through fault current for external faults (A)
I_{pn}	The rated primary CT current (A)
I_{sn}	The rated secondary CT current (A)
R_{CT}	The secondary resistance of the CT (Ω)
R_L	The resistance of the secondary cable from the CT up to a common junction point (Ω). The loop resistance containing the phase and neutral wires, must be used for faults in solidly grounded systems and the resistance of a single-phase wire should be used for faults in high impedance grounded systems.

All CTs to the same protection should have identical turn ratios. Consequently auxiliary CTs cannot normally be used. The IED must be provided with separate cores.

18.1.6.3 Breaker failure protection

The CTs must have a rated equivalent secondary e.m.f. E_{al} that is larger than or equal to the required secondary e.m.f. E_{alreq} below:

$$E_{al} \geq E_{alreq} = 5 \cdot I_{op} \cdot \frac{I_{sn}}{I_{pn}} \cdot \left(R_{CT} + R_L + \frac{S_R}{I_n^2} \right)$$

(Equation 90)

where:

I_{op}	The primary operate value (A)
I_{pn}	The rated primary CT current (A)
I_{sn}	The rated secondary CT current (A)
I_n	The nominal current of the protection IED (A)
R_{CT}	The secondary resistance of the CT (Ω)
R_L	The resistance of the secondary cable and additional load (Ω). The loop resistance containing the phase and neutral wires, must be used for faults in solidly grounded systems. The resistance of a single secondary wire should be used for faults in high impedance grounded systems.
S_R	The burden of an IED current input channel (VA). S_R=0.010 VA/channel for I_r=1 A and S_R=0.250 VA/channel for I_r=5 A

18.1.6.4 Non-directional instantaneous and definitive time, phase and residual overcurrent protection

The CTs must have a rated equivalent secondary e.m.f. E_{al} that is larger than or equal to the required secondary e.m.f. E_{alreq} below:

$$E_{al} \geq E_{alreq} = 1.5 \cdot I_{op} \cdot \frac{I_{sn}}{I_{pn}} \cdot \left(R_{CT} + R_L + \frac{S_R}{I_n^2} \right)$$

(Equation 91)

where:

I_{op}	The primary operate value (A)
I_{pn}	The rated primary CT current (A)
I_{sn}	The rated secondary CT current (A)
I_n	The nominal current of the protection IED (A)
R_{CT}	The secondary resistance of the CT (Ω)
R_L	The resistance of the secondary cable and additional load (Ω). The loop resistance containing the phase and neutral wires, must be used for faults in solidly grounded systems. The resistance of a single secondary wire should be used for faults in high impedance grounded systems.
S_R	The burden of an IED current input channel (VA). S_R=0.010 VA/channel for I_r=1 A and S_R=0.250 VA/channel for I_r=5 A

18.1.6.5 Non-directional inverse time delayed phase and residual overcurrent protection

The requirement according to Equation 92 and Equation 93 does not need to be fulfilled if the high set instantaneous or definitive time stage is used. In this case Equation 91 is the only necessary requirement.

If the inverse time delayed function is the only used overcurrent protection function the CTs must have a rated equivalent secondary e.m.f. E_{al} that is larger than or equal to the required secondary e.m.f. E_{alreq} below:

$$E_{al} \geq E_{alreq} = 20 \cdot I_{op} \cdot \frac{I_{sn}}{I_{pn}} \cdot \left(R_{CT} + R_L + \frac{S_R}{I_n^2} \right)$$

(Equation 92)

where

I_{op}	The primary current set value of the inverse time function (A)
I_{pn}	The rated primary CT current (A)
I_{sn}	The rated secondary CT current (A)
I_n	The nominal current of the protection IED (A)
R_{CT}	The secondary resistance of the CT (Ω)
R_L	The resistance of the secondary cable and additional load (Ω). The loop resistance containing the phase and neutral wires, must be used for faults in solidly grounded systems. The resistance of a single secondary wire should be used for faults in high impedance grounded systems.
S_R	The burden of an IED current input channel (VA). S_R=0.010 VA/channel for I_r=1 A and S_R=0.250 VA/channel for I_r=5 A

Independent of the value of I_{op} the maximum required E_{al} is specified according to the following:

$$E_{al} \geq E_{alreq\,max} = I_{k\,max} \cdot \frac{I_{sn}}{I_{pn}} \cdot \left(R_{CT} + R_L + \frac{S_R}{I_n^2} \right)$$

(Equation 93)

where

I_{kmax}	Maximum primary fundamental frequency current for close-in faults (A)

18.1.6.6 Directional phase and residual overcurrent protection

If the directional overcurrent function is used the CTs must have a rated equivalent secondary e.m.f. E_{al} that is larger than or equal to the required equivalent secondary e.m.f. E_{alreq} below:

$$E_{al} \geq E_{alreq} = I_{kmax} \cdot \frac{I_{sn}}{I_{pn}} \cdot \left(R_{CT} + R_L + \frac{S_R}{I_n^2} \right)$$

(Equation 94)

where:

I_{kmax}	Maximum primary fundamental frequency current for close-in forward and reverse faults (A)
I_{pn}	The rated primary CT current (A)
I_{sn}	The rated secondary CT current (A)
I_n	The rated current of the protection IED (A)
R_{CT}	The secondary resistance of the CT (Ω)
R_L	The resistance of the secondary cable and additional load (Ω). The loop resistance containing the phase and neutral wires, must be used for faults in solidly grounded systems. The resistance of a single secondary wire should be used for faults in high impedance grounded systems.
S_R	The burden of an IED current input channel (VA). S_r=0.010 VA/channel for I_r=1 A and S_r=0.250 VA/ channel for I_r=5 A

18.1.7 Current transformer requirements for CTs according to other standards

All kinds of conventional magnetic core CTs are possible to use with the IEDs if they fulfill the requirements corresponding to the above specified expressed as the rated equivalent secondary e.m.f. E_{al} according to the IEC 60044-6 standard. From different standards and available data for relaying applications it is possible to approximately calculate a secondary e.m.f. of the CT comparable with E_{al}. By comparing this with the required secondary e.m.f. E_{alreq} it is possible to judge if the CT fulfills the requirements. The requirements according to some other standards are specified below.

18.1.7.1 Current transformers according to IEC 60044-1, class P, PR

A CT according to IEC 60044-1 is specified by the secondary limiting e.m.f. E_{2max}. The value of the E_{2max} is approximately equal to the corresponding E_{al} according to IEC 60044-6. Therefore, the CTs according to class P and PR must have a secondary limiting e.m.f. E_{2max} that fulfills the following:

$$E_{2\max} > \max E_{alreq}$$

(Equation 95)

18.1.7.2 Current transformers according to IEC 60044-1, class PX, IEC 60044-6, class TPS (and old British Standard, class X)

CTs according to these classes are specified approximately in the same way by a rated knee-point e.m.f. E_{knee} (E_k for class PX, E_{kneeBS} for class X and the limiting secondary voltage V_{al} for TPS). The value of the E_{knee} is lower than the corresponding E_{al} according to IEC 60044-6. It is not possible to give a general relation between the E_{knee} and the E_{al} but normally the E_{knee} is approximately 80 % of the E_{al}. Therefore, the CTs according to class PX, X and TPS must have a rated knee-point e.m.f. E_{knee} that fulfills the following:

$$S = TD \cdot S_{Old} + (1 - TD) \cdot S_{Calculated}$$

(Equation 96)

18.1.7.3 Current transformers according to ANSI/IEEE

Current transformers according to ANSI/IEEE are partly specified in different ways. A rated secondary terminal voltage V_{ANSI} is specified for a CT of class C. V_{ANSI} is the secondary terminal voltage the CT will deliver to a standard burden at 20 times rated secondary current without exceeding 10 % ratio correction. There are a number of standardized U_{ANSI} values for example, V_{ANSI} is 400 V for a C400 CT. A corresponding rated equivalent limiting secondary e.m.f. E_{alANSI} can be estimated as follows:

$$E_{alANSI} = \left| 20 \cdot I_{SN} \cdot R_{CT} + V_{ANSI} \right| = \left| 20 \cdot I_{SN} \cdot R_{CT} + 20 \cdot I_{SN} \cdot Z_{bANSI} \right|$$

(Equation 97)

where:

Z_{bANSI}	The impedance (that is, complex quantity) of the standard ANSI burden for the specific C class (Ω)
V_{ANSI}	The secondary terminal voltage for the specific C class (V)

The CTs according to class C must have a calculated rated equivalent limiting secondary e.m.f. E_{alANSI} that fulfills the following:

$$E_{alANSI} > \max imum\ of\ E_{alreq}$$

(Equation 98)

A CT according to ANSI/IEEE is also specified by the knee-point voltage $V_{kneeANSI}$ that is graphically defined from an excitation curve. The knee-point voltage $V_{kneeANSI}$ normally has a lower value than the knee-point e.m.f. according to IEC and BS. $V_{kneeANSI}$ can approximately be estimated to 75 % of the corresponding E_{al} according to IEC 60044 6. Therefore, the CTs according to ANSI/IEEE must have a knee-point voltage $V_{kneeANSI}$ that fulfills the following:

18.2 Voltage transformer requirements

The performance of a protection function will depend on the quality of the measured input signal. Transients caused by capacitive Coupled voltage transformers (CCVTs) can affect some protection functions.

Magnetic or capacitive voltage transformers can be used.

The capacitive voltage transformers (CCVTs) should fulfill the requirements according to the IEC 60044–5 standard regarding ferro-resonance and transients. The ferro-resonance requirements of the CCVTs are specified in chapter 7.4 of the standard.

The transient responses for three different standard transient response classes, T1, T2 and T3 are specified in chapter 15.5 of the standard. CCVTs according to all classes can be used.

The protection IED has effective filters for these transients, which gives secure and correct operation with CCVTs.

18.3 SNTP server requirements

18.3.1 SNTP server requirements

The SNTP server to be used is connected to the local network, that is not more than 4-5 switches or routers away from the IED. The SNTP server is dedicated for its task, or at least equipped with a real-time operating system, that is not a PC with SNTP server

software. The SNTP server should be stable, that is, either synchronized from a stable source like GPS, or local without synchronization. Using a local SNTP server without synchronization as primary or secondary server in a redundant configuration is not recommended.

Section 19 Glossary

AC	Alternating current
ACT	Application configuration tool within PCM600
A/D converter	Analog-to-digital converter
ADBS	Amplitude deadband supervision
AI	Analog input
ANSI	American National Standards Institute
AR	Autoreclosing
ASCT	Auxiliary summation current transformer
ASD	Adaptive signal detection
AWG	American Wire Gauge standard
BI	Binary input
BOS	Binary outputs status
BR	External bistable relay
BS	British Standards
CAN	Controller Area Network. ISO standard (ISO 11898) for serial communication
CB	Circuit breaker
CCITT	Consultative Committee for International Telegraph and Telephony. A United Nations-sponsored standards body within the International Telecommunications Union.
CCVT	Capacitive Coupled Voltage Transformer
Class C	Protection Current Transformer class as per IEEE/ ANSI
CMPPS	Combined megapulses per second
CMT	Communication Management tool in PCM600
CO cycle	Close-open cycle
Codirectional	Way of transmitting G.703 over a balanced line. Involves two twisted pairs making it possible to transmit information in both directions

COMTRADE	Standard Common Format for Transient Data Exchange format for Disturbance recorder according to IEEE/ANSI C37.111, 1999 / IEC60255-24
Contra-directional	Way of transmitting G.703 over a balanced line. Involves four twisted pairs, two of which are used for transmitting data in both directions and two for transmitting clock signals
CPU	Central processor unit
CR	Carrier receive
CRC	Cyclic redundancy check
CROB	Control relay output block
CS	Carrier send
CT	Current transformer
CVT or CCVT	Capacitive voltage transformer
DAR	Delayed autoreclosing
DARPA	Defense Advanced Research Projects Agency (The US developer of the TCP/IP protocol etc.)
DBDL	Dead bus dead line
DBLL	Dead bus live line
DC	Direct current
DFC	Data flow control
DFT	Discrete Fourier transform
DHCP	Dynamic Host Configuration Protocol
DIP-switch	Small switch mounted on a printed circuit board
DI	Digital input
DLLB	Dead line live bus
DNP	Distributed Network Protocol as per IEEE/ANSI Std. 1379-2000
DR	Disturbance recorder
DRAM	Dynamic random access memory
DRH	Disturbance report handler
DSP	Digital signal processor
DTT	Direct transfer trip scheme
EHV network	Extra high voltage network
EIA	Electronic Industries Association

EMC	Electromagnetic compatibility
EMF	(Electric Motive Force)
EMI	Electromagnetic interference
EnFP	End fault protection
EPA	Enhanced performance architecture
ESD	Electrostatic discharge
FCB	Flow control bit; Frame count bit
FOX 20	Modular 20 channel telecommunication system for speech, data and protection signals
FOX 512/515	Access multiplexer
FOX 6Plus	Compact time-division multiplexer for the transmission of up to seven duplex channels of digital data over optical fibers
G.703	Electrical and functional description for digital lines used by local telephone companies. Can be transported over balanced and unbalanced lines
GCM	Communication interface module with carrier of GPS receiver module
GDE	Graphical display editor within PCM600
GI	General interrogation command
GIS	Gas-insulated switchgear
GOOSE	Generic object-oriented substation event
GPS	Global positioning system
HDLC protocol	High-level data link control, protocol based on the HDLC standard
HFBR connector type	Plastic fiber connector
HMI	Human-machine interface
HSAR	High speed autoreclosing
HV	High-voltage
HVDC	High-voltage direct current
IDBS	Integrating deadband supervision
IEC	International Electrical Committee
IEC 60044-6	IEC Standard, Instrument transformers – Part 6: Requirements for protective current transformers for transient performance

IEC 61850	Substation automation communication standard
IEC 61850–8–1	Communication protocol standard
IEEE	Institute of Electrical and Electronics Engineers
IEEE 802.12	A network technology standard that provides 100 Mbits/s on twisted-pair or optical fiber cable
IEEE P1386.1	PCI Mezzanine Card (PMC) standard for local bus modules. References the CMC (IEEE P1386, also known as Common Mezzanine Card) standard for the mechanics and the PCI specifications from the PCI SIG (Special Interest Group) for the electrical EMF (Electromotive force).
IEEE 1686	Standard for Substation Intelligent Electronic Devices (IEDs) Cyber Security Capabilities
IED	Intelligent electronic device
I-GIS	Intelligent gas-insulated switchgear
Instance	When several occurrences of the same function are available in the IED, they are referred to as instances of that function. One instance of a function is identical to another of the same kind but has a different number in the IED user interfaces. The word "instance" is sometimes defined as an item of information that is representative of a type. In the same way an instance of a function in the IED is representative of a type of function.
IP	1. Internet protocol. The network layer for the TCP/IP protocol suite widely used on Ethernet networks. IP is a connectionless, best-effort packet-switching protocol. It provides packet routing, fragmentation and reassembly through the data link layer. 2. Ingression protection, according to IEC standard
IP 20	Ingression protection, according to IEC standard, level IP20- Protected against solidforeign objects of12.5mm diameter andgreater.
IP 40	Ingression protection, according to IEC standard, level IP40- Protected against solid foreign objects of 1mm diameter and greater.
IP 54	Ingression protection, according to IEC standard, level IP54-Dust-protected,protected againstsplashing water.
IRF	Internal failure signal
IRIG-B:	InterRange Instrumentation Group Time code format B, standard 200
ITU	International Telecommunications Union

LAN	Local area network
LIB 520	High-voltage software module
LCD	Liquid crystal display
LDD	Local detection device
LED	Light-emitting diode
MCB	Miniature circuit breaker
MCM	Mezzanine carrier module
MVB	Multifunction vehicle bus. Standardized serial bus originally developed for use in trains.
NCC	National Control Centre
OCO cycle	Open-close-open cycle
OCP	Overcurrent protection
OLTC	On-load tap changer
OV	Over-voltage
Overreach	A term used to describe how the relay behaves during a fault condition. For example, a distance relay is overreaching when the impedance presented to it is smaller than the apparent impedance to the fault applied to the balance point, that is, the set reach. The relay “sees” the fault but perhaps it should not have seen it.
PCI	Peripheral component interconnect, a local data bus
PCM	Pulse code modulation
PCM600	Protection and control IED manager
PC-MIP	Mezzanine card standard
PMC	PCI Mezzanine card
POR	Permissive overreach
POTT	Permissive overreach transfer trip
Process bus	Bus or LAN used at the process level, that is, in near proximity to the measured and/or controlled components
PSM	Power supply module
PST	Parameter setting tool within PCM600
PT ratio	Potential transformer or voltage transformer ratio
PUTT	Permissive underreach transfer trip
RASC	Synchrocheck relay, COMBIFLEX

RCA	Relay characteristic angle
RFPP	Resistance for phase-to-phase faults
	Resistance for phase-to-ground faults
RISC	Reduced instruction set computer
RMS value	Root mean square value
RS422	A balanced serial interface for the transmission of digital data in point-to-point connections
RS485	Serial link according to EIA standard RS485
RTC	Real-time clock
RTU	Remote terminal unit
SA	Substation Automation
SBO	Select-before-operate
SC	Switch or push button to close
SCS	Station control system
SCADA	Supervision, control and data acquisition
SCT	System configuration tool according to standard IEC 61850
SDU	Service data unit
SMA connector	Subminiature version A, A threaded connector with constant impedance.
SMT	Signal matrix tool within PCM600
SMS	Station monitoring system
SNTP	Simple network time protocol – is used to synchronize computer clocks on local area networks. This reduces the requirement to have accurate hardware clocks in every embedded system in a network. Each embedded node can instead synchronize with a remote clock, providing the required accuracy.
SRY	Switch for CB ready condition
ST	Switch or push button to trip
Starpoint	Neutral/Wye point of transformer or generator
SVC	Static VAr compensation
TC	Trip coil
TCS	Trip circuit supervision
TCP	Transmission control protocol. The most common transport layer protocol used on Ethernet and the Internet.

TCP/IP	Transmission control protocol over Internet Protocol. The de facto standard Ethernet protocols incorporated into 4.2BSD Unix. TCP/IP was developed by DARPA for Internet working and encompasses both network layer and transport layer protocols. While TCP and IP specify two protocols at specific protocol layers, TCP/IP is often used to refer to the entire US Department of Defense protocol suite based upon these, including Telnet, FTP, UDP and RDP.
TNC connector	Threaded Neill-Concelman, a threaded constant impedance version of a BNC connector
TPZ, TPY, TPX, TPS	Current transformer class according to IEC
UMT	User management tool
Underreach	A term used to describe how the relay behaves during a fault condition. For example, a distance relay is underreaching when the impedance presented to it is greater than the apparent impedance to the fault applied to the balance point, that is, the set reach. The relay does not “see” the fault but perhaps it should have seen it. See also Overreach.
UTC	Coordinated Universal Time. A coordinated time scale, maintained by the Bureau International des Poids et Mesures (BIPM), which forms the basis of a coordinated dissemination of standard frequencies and time signals. UTC is derived from International Atomic Time (TAI) by the addition of a whole number of "leap seconds" to synchronize it with Universal Time 1 (UT1), thus allowing for the eccentricity of the Earth's orbit, the rotational axis tilt (23.5 degrees), but still showing the Earth's irregular rotation, on which UT1 is based. The Coordinated Universal Time is expressed using a 24-hour clock, and uses the Gregorian calendar. It is used for aeroplane and ship navigation, where it is also sometimes known by the military name, "Zulu time." "Zulu" in the phonetic alphabet stands for "Z", which stands for longitude zero.
UV	Undervoltage
WEI	Weak end infeed logic
VT	Voltage transformer
X.21	A digital signalling interface primarily used for telecom equipment
$3I_O$	Three times zero-sequence current. Often referred to as the residual or the -fault current

$3V_O$	Three times the zero sequence voltage. Often referred to as the residual voltage or the neutral point voltage

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